Appendix B. Four-Factor Analyses - Facility Responses

This appendix contains the information provided by facilities in response to MPCA's request to prepare a four-factor analysis for specifically identified emission units. The table below summarizes which facilities and emission units that the MPCA requested to conduct a four-factor analysis.

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

- The remaining useful life of specific emission units at their sources.
- The effectiveness of the existing controls on specific emission units at their sources.
- Responses to questions/comments provided by the MPCA, FLMs, or U.S. EPA.

The additional information provided by these sources is available in this appendix as well.

Table B-1. Four-factor analyses requested by MPCA

Facility name	Emission unit	Emission unit ID		Pollutants
		(Tempo)	(Delta)	
American Crystal Sugar - Crookston	Boiler 1	EQUI 14	EU 001	NO_X, SO_2
	Boiler 2	EQUI 15	EU 002	NO_X, SO_2
	Boiler 3	EQUI 16	EU 003	NO_X, SO_2
American Crystal Sugar - East Grand Forks	Boiler 1	EQUI 18	EU 001	NO_X, SO_2
	Boiler 2	EQUI 19	EU 002	NO_X, SO_2
Boise White Paper	Recovery Furnace	EQUI 9	EU 320	NO_X
	Boiler 1	EQUI 15	EU 420	NO_X
	Boiler 2	EQUI 16	EU 430	NO_X, SO_2
Cleveland Cliffs Minorca Mine Inc.	Indurating Machine	EQUI 38	EU 026	NO_X, SO_2
Hibbing Public Utilities Commission	Boiler No. 1A	EQUI 1	EU 001	NO_X, SO_2
	Boiler No. 2A	EQUI 2	EU 002	NO_X, SO_2
	Boiler No. 3A	EQUI 3	EU 003	NO_X, SO_2
	Wood Fired Boiler	EQUI 7	EU 007	NO_X
Hibbing Taconite Company	Indurating Furnace Line 1	EQUI 95	EU 020	NO_X, SO_2
	Indurating Furnace Line 2	EQUI 96	EU 021	NO_X, SO_2
	Indurating Furnace Line 3	EQUI 97	EU 022	NO_X, SO_2
Minnesota Power - Boswell Energy Center	Unit 1	EQUI 82	EU 001	NO_X, SO_2
	Unit 2	EQUI 83	EU 002	NO_X, SO_2
	Unit 3	EQUI 100	EU 003	NO_X, SO_2
	Unit 4	EQUI 85	EU 004	NO_X, SO_2
Minnesota Power - Taconite Harbor Energy	Boiler 1	EQUI 64	EU 001	NO_X, SO_2
	Boiler 2	EQUI 5	EU 002	NO_X, SO_2
Northshore Mining - Silver Bay	Power Boiler 1	EQUI 14	EU 001	NO_X, SO_2
	Power Boiler 2	EQUI 15	EU 002	NO_X, SO_2
	Furnace 11	EQUI 126 & 127	EU 100 & 104	NO_X, SO_2
	Furnace 12	EQUI 128 & 129	EU 110 & 114	NO_X, SO_2

Facility name	Emission unit	Emission unit ID		Pollutants
		(Tempo)	(Delta)	
Sappi Cloquet LLC	Power Boiler #9	EQUI 4	EU 004	NO_X, SO_2
	Recovery Boiler #10	EQUI 53	EU 005	NO_X
Southern Minnesota Beet Sugar Cooperative	Boiler 1	EQUI 17	EU 001	NO_X, SO_2
United Taconite LLC - Fairlane Plant	Line 1 Pellet Induration	EQUI 45	EU 040	NO_X, SO_2
	Line 2 Pellet Induration	EQUI 47	EU 042	NO_X, SO_2
US Steel Corporation - Keetac	Grate Kiln	EQUI 97	EU 030	NO_X, SO_2
US Steel Corporation - Minntac	Line 3 Rotary Kiln	EQUI 146	EU 225	NO_X, SO_2
	Line 4 Rotary Kiln	EQUI 279	EU 261	NO_X, SO_2
	Line 5 Rotary Kiln	EQUI 280	EU 282	NO_X, SO_2
	Line 6 Rotary Kiln	EQUI 3	EU 315	NO_X, SO_2
	Line 7 Rotary Kiln	EQUI 179	EU 334	NO_X, SO_2
Virginia Department of Public Utilities	Boiler 7	EQUI 2	EU 001	NO_X, SO_2
	Boiler 9	EQUI 3	EU 003	NO_X, SO_2
	Boiler 11	EQUI 16	EU 006	NO_X
Xcel Energy - Allen S. King	Boiler 1	EQUI 68	EU 001	NO_X, SO_2
Xcel Energy - Sherburne	Unit 1	EQUI 92	EU 001	NO_X, SO_2
	Unit 2	EQUI 93	EU 002	NO_X, SO_2
	Unit 3	EQUI 94	EU 003	NO_X, SO_2

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February 14, 2020

Douglas Emerson, Environmental Affairs Manager
American Crystal Sugar - Crookston
1201 Highway 75 South
Crookston, MN 56716

RE: Request for Information - Regional Haze Rule, Reasonable Progress, Four Factor Analysis

Dear Mr. Emerson:

The Minnesota Pollution Control Agency (MPCA) is currently preparing information for the second planning period (Round 2) comprehensive update to Minnesota's Regional Haze State Implementation Plan (SIP) as required by the Regional Haze Rule (40 CFR § 51.308). States are responsible for developing a Regional Haze SIP that addresses regional haze in each Class I area located within the state and in each Class I area located outside the state which may be affected by emissions from sources within the state. The Regional Haze SIP is required to identify existing facilities that cause or contribute to visibility impairment; analyze, identify, and apply federally-enforceable control strategies for those sources; and periodically demonstrate reasonable progress toward reaching visibility goals. States are also responsible for periodic comprehensive updates to their Regional Haze SIP that address these same topics. Minnesota's Round 2 Regional Haze SIP must be submitted to the U.S. Environmental Protection Agency (U.S. EPA) by July 31, 2021.

Minnesota has two Class I areas within its borders, the Boundary Waters Canoe Area Wilderness (BWCA) and Voyageurs National Park (Voyageurs). Other nearby Class I areas include Isle Royale National Park in Michigan. Therefore, Minnesota must prepare a Regional Haze SIP that identifies sources that cause or contribute to visibility impairment in these areas. To meet the core requirements for regional haze for these areas, Minnesota must submit a SIP that contains the plan elements and supporting documentation for all required analyses identified in 40 CFR § 51.308(f).

In the first planning period (Round 1), the focus of the Regional Haze Rule was on establishing Best Available Retrofit Technology (BART) for certain older sources and reasonable progress towards national visibility goals. In Round 2, there are no BART requirements; therefore, the focus is on making reasonable progress. The U.S. Environmental Protection agency has defined the methodology that states must use to determine what measures are necessary to make reasonable progress in 40 CFR § 51.308(f)(2). At minimum, the reasonable progress analysis must use the four factors identified in 40 CFR § 51.308(f)(2)(i) to evaluate and determine the emission reduction measures necessary to make reasonable progress. The four factors are:

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

Data from the IMPROVE monitoring sites at BWCA and Voyageurs indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X).

You are receiving this letter because your facility was identified as a significant source of NO_X and SO_2 and is located close enough to the BWCA or Voyageurs to potentially cause or contribute to visibility impairment in these Class I areas. Therefore, the MPCA requests that you prepare a "Four Factor Analysis" for the following emission units:

1. Boiler #1 (EQUI 14 / EU 001) that addresses emissions of NO_X and SO_2
2. Boiler #2 (EQUI 15 / EU 002) that addresses emissions of NO_X and SO_2
3. Boiler #3 (EQUI 16 / EU 003) that addresses emissions of NO_X and SO_2

The analysis should be prepared using the U.S. Environmental Protection Agency guidance[1] that provides recommendations for how each of the factors should be determined.

Preparation of the comprehensive update to Minnesota's Regional Haze SIP will require extensive planning and review of sources in Minnesota. The MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to prepare the Regional Haze SIP. The MPCA expects air quality modeling of potential regional emissions reductions will be conducted beginning in spring 2020. I appreciate your attention to this matter and request that you **submit the Four Factor Analysis by July 31, 2020**.

If you have any questions regarding this matter, or would like to request a meeting to further discuss the contents of this letter, please contact me by phone at 651-757-2653 or by email at Hassan.Bouchareb@state.mn.us.

Sincerely,

Hassan Bouchareb

This document has been electronically signed.

Hassan M. Bouchareb
Engineer
Environmental Analysis and Outcomes Division

Cc: Deepa de Alwis, MPCA
Cory Boeck, MPCA
Frank Kohlasch, MPCA
Agency Interest ID 2381

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---

[1] **U.S. Environmental Protection Agency.** *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 20, 2019, https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

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February 14, 2020

Douglas Emerson, Environmental Affairs Manager
American Crystal Sugar - East Grand Forks
1020 Business Highway 2
East Grand Forks, MN 56721

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Sincerely,

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This document has been electronically signed.

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[1] **U.S. Environmental Protection Agency.** *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 20, 2019, https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

Regional Haze Four Factor Analysis

American Crystal Sugar Company

Crookston, MN

For Submittal to:
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155-4194

August 28, 2020

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Appendix A. Cost Calculations

1 Introduction

In response to the Minnesota Pollution Control Agency (MPCA) Request for Information (ROI) dated February 14, 2020, American Crystal Sugar Company (ACSC) is providing the following Four Factor Analysis to address pollutants of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emitted from the coal-fired boilers at the Crookston (CRK) facility.

This analysis is being provided for planning purposes and is based on budgetary cost information obtained from scaled vendor quotes for similar systems as well as methodology presented in the U.S. Environmental Protection Agency's (EPA) Air Pollution Control Cost Manual. This approach is intended to provide a study-level estimate (+/-30%) of capital and annual costs. In the event that emission reductions will be proposed for inclusion in the State Implementation Plan (SIP), it is requested that ACSC be given the opportunity to further refine the cost data to incorporate site-specific quotes reflecting current market conditions and unique site physical constraints.

1.1 Analysis Methodology

Following the U.S. Environmental Protection Agency (EPA) *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 20, 2019, the Four Factor Analysis addresses:

- The costs of compliance;
- The time necessary for compliance;
- The energy and non-air quality environmental impacts of compliance; and,
- The remaining useful life of the source(s).

The first step in the process is identification of all available retrofit technologies for each pollutant (SO_2 and NO_x). Control options that are technically infeasible are eliminated and options are evaluated to determine their control effectiveness and economic, energy and environmental impacts.

Technically feasible control technologies are ranked in the order of highest expected emission reduction to lowest expected emission reduction and are evaluated following a "top-down" approach similar to Best Available Control Technology (BACT) analyses.

Impacts considered for each control technology include: cost of compliance, energy impacts, non-air quality environmental impacts and the remaining useful life of the unit to be controlled.

1.2 CRK Source Parameters

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 electrostatic precipitators 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 (PRB).

The boilers are identified as EU001, EU002, and EU003 in Air Emission Permit No. 11900001-004. The operating permit limits each boiler to the maximum emission rates shown in Table 1 below.

Table 1 – Permitting Emission Limits.

Pollutant	Boiler 1 – EU001	Boiler 2 – EU002	Boiler 3 – EU003
SO_2	127 (0.93 lb/MMBtu)	127 lb/hr (0.93 lb/MMBtu)	154 lb/hr (0.93 lb/MMBtu)
NO_x	99.8 lb/hr (0.73 lb/MMBtu)	99.8 lb/hr (0.73 lb/MMBtu)	120 lb/hr (0.73 lb/MMBtu)

As indicated in the EPA's *Guidance on Regional Haze State Implementation Plans*, a state may use a source's annual emissions in tons to determine actual visibility impacts. Therefore, actual emission levels based on source test data were used to characterize emissions-related factors in this analysis. The average SO_2 emission rate from the two identical CRK boilers as reported in the most recent emission inventory is 0.37 lb/MMBtu and 241 tons per year (tpy) for each boiler. The SO_2 emission rate from the slightly larger boiler is 0.41 lb/MMBtu and 253 tpy. The average NO_x emission rate from the two identical CRK boilers as reported in the most recent emission inventory is 0.33 lb/MMBtu and 209 tpy for each boiler. The NO_x emission rate from the slightly larger boiler is 0.32 lb/MMBtu and 202 tpy.

Because two of the boilers are of identical size and type, control technology costs and design features would be the same for both boilers. The third boiler is of the same type, but slightly larger. It is anticipated that the Four Factor Analysis applies to the CRK facility as a whole, and two potential control technology determinations could be made: one for the identical boilers, and one for the slightly larger single boiler at the facility. The average emission rate for the two identical boilers was used in the analysis to determine costs of compliance for those units and the individual emission rate was used for the slightly larger boiler.

2 Four Factor Analysis

2.1 Applicable Pollutants

The Four Factor Analysis addresses criteria pollutants of SO_2 and NO_x.

SO_2 Formation. SO_2 emissions are formed from the oxidation of organic sulfur and pyritic sulfur in the coal during the combustion process. The majority of sulfur is oxidized to SO_2, however, a small quantity may be further oxidized to form sulfur trioxide (SO_3). Approximately 90% of the sulfur present in the subbituminous coal will be emitted as sulfur oxides (SO_x) compounds. Alkaline ash from some coals (including PRB coals) may cause some of the sulfur to react in the furnace to form various sulfate salts that are then retained in the fly ash. Sulfuric acid mist (H_2SO_4) forms when SO_2 emissions react with moisture and oxygen in the environment.

NO_x Formation. There are two primary mechanisms of NO_x formation in coal-fired industrial boilers: thermal production of NOx from atmospheric nitrogen and oxygen, and oxidation of nitrogen bound in the fuel. High combustion temperatures cause the nitrogen (N_2) and oxygen (O_2) molecules in the combustion air to react and form thermal NO_x. Because thermal NO_x is primarily a function of combustion temperature, NO_x emission rates vary with burner and source design. Experimental measurements of thermal NO_x formation have shown that the NO_x concentration is exponentially dependent on temperature and is proportional to the N_2 concentration in the flame, the square root of the O_2 concentration in the flame, and the gas residence time[1]. The formation of fuel NO_x from reactions of fuel bound nitrogen and air can account for up to 80% of total NO_x from coal combustion. Subbituminous coals contain from 0.5 to 2 percent by weight fuel-bound nitrogen.

2.2 Economic Evaluation Criteria

Costs of compliance are directly related to the technically feasible control technology option selected and the level of emission reduction experienced from the control. Costs are expressed in terms of dollars per ton of pollutant removed, where the cost is the annualized capital and operating costs, and the tons of pollutant removed is the incremental reduction in pollutant emissions over current baseline (actual) emission levels.

Base economic criteria used in this analysis are listed in Table 2.

Table 2 – Economic Evaluation Criteria.

Economic Parameter	Value
Interest Rate, percent	7[A]
Control Equipment Economic Life, years	15 & 20[B]
Base Labor Cost, $/hr	60[C]
Energy Cost, $/kW-hr	0.06[D]

[A] EPA Air Pollution Control Cost Manual, Seventh Edition, January 2017, Chapter 2, Section 2.4.2.
[B] EPA Memorandum, Calculating Amortized Capital Costs, July 24, 1987, Robert D. Bauman, Chief, Standards and Implementation Branch.
[C] Loaded labor rate obtained from ACSC.
[D] Actual ACSC electricity cost.

Cost estimates used in the analysis have been compile from a number of data sources. In general, the cost estimates were performed following guidance provided in the EPA Air Pollution Control Cost Manual, Seventh Edition, January 2017. The EPA control cost manual data was

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[1] AP42, Chapter 1, Bituminous and Subbituminous Coal Combustion, (9/98).

supplemented with vendor supplied quotations when available and general engineering estimates. Detailed cost estimate and support data have been provided in Appendix A.

2.3 SO_2 Analysis

Because two of the coal-fired boilers at the CRK facility are identical, the analysis was prepared for one individual boiler at that capacity. The results of the analysis can be applied equally to each boiler. A separate analysis was performed for the third, slightly larger boiler.

2.3.1 Identification of SO_2 Control Technologies

Control of SO_2 emissions from fuel-combustion sources can be accomplished through two approaches: removal of elemental sulfur from the fuel prior to combustion, and flue gas desulfurization (FGD), which consists of removal of SO_2 from flue gas after combustion (post-combustion control).

Many oil refineries operate catalyst-based desulfurization units to remove organic sulfur from liquid crude oil. However, in solid fuels, such as coal, a significant fraction of the sulfur is in the form of pyrite (FeS_2) or other mineral sulfates. It is possible to remove some mineral sulfates through physical processes such as washing and/or chemical processing. However, desulfurization of solid fuels is generally viewed as inefficient and expensive. Additionally, organic sulfur cannot be removed by physical cleaning. It is unlikely that sufficient desulfurization of solid fuels can be accomplished to meet anticipated emission requirements. Therefore removal of sulfur from the coal prior to combustion will not be considered a viable option for this analysis.

FGD technologies can be divided into two main categories: regenerative and throwaway processes. Regenerative processes recover sulfur in a usable form that can be sold as a reusable sulfur product. Throwaway processes remove sulfur from flue gas and scrubber byproducts are subsequently discarded. All of the FGD technologies considered can achieve SO_2 removal efficiencies of 90 to 95% depending on the amount of sulfur in the coal. For relatively high sulfur coals, removal efficiencies can exceed 95%, while for lower sulfur coals (such as PRB), the achievable removal efficiency is typically less than 95%.

Regenerative processes, by nature, contain a regeneration step in the FGD process that results in higher costs than throwaway processes due to equipment and operation expenses. However, in instances where disposal options are limited and markets for recovered sulfur products are readily available, regenerative processes may be used. Potential regenerative processes that are available include the Wellman-Lord (W-L) process, magnesium oxide process, citrate scrubbing process, Flakt-Boliden process, aqueous carbonate process, Sulf-X process, Conosox process, Westvaco process and adsorption of SO_2 by a bed of copper oxide.

Throwaway processes such as limestone scrubbing have become widely accepted by the coal-fired power industry for FGD because limestone scrubbers have overall lower costs and are simpler to operate than regenerative processes. Because the throwaway process can achieve the same removal efficiencies as regenerative processes and cost less, this analysis for SO_2 will focus on throwaway processes and further discussion of regenerative processes will not be considered.

Throwaway processes can be divided into two categories, wet and dry. Wet or dry refers to the state of the waste by-products. Both wet and dry technologies have advantages and disadvantages with respect to initial capital and operational expenses.

2.3.1.1 Wet FGD Systems

Wet scrubbing (wet FGD) systems used for SO_2 reduction typically consist of the following operations: scrubbing or absorption, lime handling and slurry preparation, sludge processing, and flue gas handling.

Wet FGD technology is a well-established process for removing SO_2 from flue gas. In wet scrubbers, the flue gas enters a spray tower or absorber where it is sprayed with a water slurry, which is approximately 10 percent lime or limestone. Sodium alkali solutions can also be used in FGD systems, however these processes are considerably more expensive than lime. The preferred sorbents are limestone and lime, respectively, due to the availability and relatively low cost of limestone. Calcium in the slurry reacts with the SO_2 in the flue gas to form calcium sulfite or calcium sulfate. The overall chemical reaction can be simply expressed as:

$$SO_2 + CaCO_3 \rightarrow CaSO_3 + CO_2$$

Spent slurry from the reaction tank is pumped into a thickener where solids settle before being filtered for final dewatering to approximately 50 percent solids. Water removed during this process is sent to a process water holding tank, which eventually will require wastewater treatment. In a non-regenerative system, the waste sludge must also be disposed of properly. Finally, scrubbed flue gases are directed through a stack gas reheater in order to minimize corrosion downstream of the scrubber due to conversion of SO_2 to SO_3 and subsequently sulfuric acid (H_2SO_4). Reheating is sometimes needed for proper drafting and rise of exhaust gases out the stack, as well as minimizing condensation. As an alternative, the stack can be constructed of acid resistant material.

Most wet FGD systems have two stages: one for fly ash removal and one for SO_2 removal. The flue gas normally passes first through a fly ash removal device, either an electrostatic precipitator (ESP) or a bag filter, and then into the SO_2 absorber. There are many different types of absorbers that can be used in wet FGD systems, including: spray towers, venturis, plate towers, and mobile packed beds. However, many of these systems can result in scale buildup, plugging or erosion, which can affect the dependability and efficiency of the absorber. Therefore, simple scrubbers such as spray towers are commonly used. The chief drawback of the spray tower design is that it requires a higher liquid-to-gas ratio for equivalent removal of SO_2 than other absorber designs.

2.3.1.2 Dry FGD Systems

In contrast to wet scrubbing systems, dry FGD (spray dryer) systems use much smaller amounts of liquid. With a spray dryer system, the flue gases enter an absorbing tower (dryer) where the hot gases are contacted with a finely atomized slurry, which is usually a calcium-based sorbent such as calcium hydroxide or calcium oxide (lime). Acid gases and SO_2 are absorbed by the slurry mixture and react to form solid salts. The heat of the flue gas evaporates the water droplets in the sprayed slurry, and a non-saturated flue gas exits the absorber tower. The absorption process is also somewhat temperature dependent. Cooler flue gases allow the acid gases to more effectively react with the sorbents. The overall chemical reactions can be simply expressed as:

$$Ca(OH)_2 + SO_2 \rightarrow CaSO_3(s) + H_2O$$

$$Ca(OH)_2 + 2HCl \rightarrow CaCl_2\ (s) + 2H_2O$$

As can be seen above, one mole of calcium hydroxide will neutralize one mole of SO_2, whereas one mole of calcium hydroxide will neutralize two moles of hydrochloric acid (HCl). A similar reaction occurs with the neutralization of hydrofluoric acid (HF). These reactions demonstrate that when using a spray dryer the HCl and HF are removed more readily than SO_2. Reagent requirements should consider that the HCl and HF are removed first, followed by the reagent quantity required to remove the SO_2[2].

The heat of the flue gas evaporates the water droplets in the sprayed slurry, and a non-saturated flue gas exists the absorber tower. The exhaust stream exiting the absorber contains fly ash, calcium salts, and un-reacted lime, which must be sent to a particulate control device such as a fabric filter (baghouse). The particulate control device not only is necessary to control particulate matter, but also aids in acid-gas removal. Acid gases are removed when the flue gas comes in contact with the lime-containing particles on the surface of the ESP or baghouse. Fabric filters are considered to have slightly higher residual acid gas removal levels than ESPs because the acid gases must pass through the lime-containing filter cake in a fabric filter system. Modern dry FGD systems include a loop to recycle a portion of the baghouse-collected material for re-use in the FGD module because this material contains a relatively high amount of unreacted lime.

A lower efficiency Dry FGD process that utilizes either wet or dry reagent injected directly into the furnace or flue gas duct is known as dry sorbent injection (DSI). In general, hydrated lime, lime slurry or powdered lime is injected into the existing furnace or ductwork. The constraints of the existing furnace and ductwork configuration may limit expected retrofit control efficiencies of SO_2, which range from 25 to 50%. A significant drawback of this type of system is the increased maintenance costs incurred from directly injecting a sorbent into the furnace and associated duct work and the potential to significantly reduce the useful life of the boiler. Although DSI is a type of Dry FGD process, it will be referred to separately in this analysis.

2.3.2 SO_2 Control Technology Effectiveness

Effectiveness is measured by the amount of SO_2 removed from each control technology based on a comparison of the controlled emission rates to the baseline emission rates of the boilers. Table 3 provides a summary of the SO_2 control technology effectiveness.

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[2] Karl B. Schnelle, Jr. and Charles A. Brown, Air Pollution Control Technology Handbook, CRC Press, 2002.

Table 3 – SO_2 Control Technology Effectiveness.

Control Technology	Percent SO_2 Reduction[A]	Emission Rate (lb/MMBtu)	Annual Emissions (tpy)	Tons SO_2 Removed (tpy)
Two Identical Boilers (EU001 & EU002)				
Baseline	0	0.37	241	NA
Wet FGD	80	0.07	48	193
Dry FGD	80	0.07	48	193
DSI	30	0.26	169	72
Slightly Larger Boiler (EU003)				
Baseline	0	0.41	253	NA
Wet FGD	80	0.08	51	202
Dry FGD	80	0.08	51	202
DSI	30	0.29	177	76

[A] Control efficiency is the lowest expected end of the range due to the combustion of low sulfur PRB coals and high relative flue gas flowrate for boiler design.

As indicated in Table 3, it is anticipated that the same level of SO_2 control can be achieved by the use of either Dry or Wet FGD spray dryer systems (non-DSI). This assumption is based on observation of FGD control in use on coal-fired utility boilers.

In general terms, removal of high concentrations of SO_2 in the flue gas is easily accomplished using either Dry or Wet FGD. Lower concentrations become more difficult to control and require greater amounts of reagent. Historically, Wet FGD systems have been used on higher-sulfur eastern coals, leading to higher efficiencies cited for Wet FGD systems, given there is much more sulfur to control. However, on lower-sulfur western coals (such as the PRB coal used at CRK) modern Dry FGD systems with better atomizer systems in conjunction with modern fabric filter technology can perform as well as Wet FGD systems. Much of the final SO_2 control in a Dry FGD system takes place in the reagent-rich filter cake on the fabric filter.

Because of the equivalency in anticipated SO_2 emission rates, only Dry FGD technology is considered in this analysis. Dry FGD technology was selected as it has lower capital and operating costs than Wet FGD and will result in a more cost-effective approach. Furthermore, use of Wet FGD to control SO_2 emissions from the CRK boilers would result in both higher energy penalties to the facility operations and the generation of more waste byproducts than would Dry FGD. Increased energy penalties would be due to the additional pumps and water handling equipment required for slurry preparation for the Wet FGD, which would also lead to the creation of additional waste byproducts from the spent slurry. Dewatering of the spent slurry results in the production of a wastewater stream, as well as a waste sludge that must be disposed of in a landfill. Dry FGD results only in a dry product which is easily landfilled.

The lower control efficiencies of 80 and 30% anticipated for the Dry FGD and DSI systems, respectively, are based on the fact the CRK boilers combust low sulfur PRB coal and have relatively high flue gas flow rates associated with the OFA system, resulting in lower starting SO_2 concentrations. Additionally, because the boilers have a smaller than typical furnace size for the type of coal combusted, boiler slagging and maintenance is higher than typical. As a result, the introduction of large amounts of sorbent into the furnace and high temperature flue gas (such as with DSI systems) is anticipated to magnify these issues and result in a detrimental impact on operation and efficiency. Furthermore, frequent process load swings resulting from varying production demands presents difficulties with balancing sorbent injection and maintaining consistent control.

2.3.3 Evaluation of Impacts

The following sections present a detailed evaluation of the impacts of employing Dry FGD and DSI to control SO_2 emissions from the CRK boilers. The four factors assessed include: cost of compliance, energy, non-air quality environmental impacts and remaining useful life.

2.3.3.1 Cost of Compliance

Table 3 summarizes the capital and annual operating costs associated with retrofitting a Dry FGD and DSI system to each of the identical smaller CRK boilers (EU001 and EU002). Table 5 summarizes the same costs, adjusted for the slightly larger boiler (EU003). Detailed cost estimates indicating data sources for each cost category have been included in Appendix A.

Table 4 – SO_2 Costs of Compliance – EU001 & EU002 (per Boiler).

Description	Technology Option	
	Dry FGD w/Fabric Filter	DSI
Emission Rate (lb/MMBtu)	0.07	0.26
Emission Reduction (tpy)	193	72
Capital Cost ($)	14,425,400	2,966,900
Direct Annual Cost ($)	1,112,000	136,300
Indirect Annual Cost ($)	2,536,500	509,400
Total Annualized Cost ($)	3,648,500	645,700
Cost Effectiveness, per Boiler ($/ton)	18,900	9,000

Table 5 – SO_2 Costs of Compliance – EU003.

Description	Technology Option	
	Dry FGD w/Fabric Filter	DSI
Emission Rate (lb/MMBtu)	0.08	0.29
Emission Reduction (tpy)	202	76
Capital Cost ($)	15,978,300	3,306,900
Direct Annual Cost ($)	1,205,800	143,700
Indirect Annual Cost ($)	2,790,900	562,700
Total Annualized Cost ($)	3,996,700	706,400
Cost Effectiveness ($/ton)	19,800	9,300

2.3.3.2 Energy Impact

Use of Dry FGD or DSI to control SO_2 emissions from the CRK boilers would result in energy penalties to facility operations in the form of the electricity demand required for operation of ancillary equipment such as the reagent preparation and atomizer equipment, as well as additional backpressure on the exhaust system that results in decreased operational efficiency.

2.3.3.3 Non-Air Quality Environmental Impacts

The primary detrimental non-air quality environmental impact of a Dry FGD or DSI system is the creation of a solid waste byproduct from the spent reagent. Unlike Wet FGD, there is no wastewater stream resultant from the use of Dry FGD. The solid waste that is produced from a Dry FGD system can be landfilled or possibly used as an agricultural soil supplement depending on the fly ash content.

The DSI system is anticipated to greatly increase maintenance requirements as a result of increased boiler slagging and equipment fouling. Given the age of the existing boilers, the implementation of such a system may have a significant negative impact on remaining useful life.

2.3.3.4 Remaining Useful Life

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.

2.4 NO_x Analysis

Because two of the coal-fired boilers at the CRK facility are identical, the analysis was prepared for one individual boiler at that capacity. The results of the analysis can be applied equally to each boiler. A separate analysis was performed for the third, slightly larger boiler.

2.4.1 Identification of NOx Control Technologies

Control of NO_x emissions from boilers can be attained through either the application of combustion controls or flue gas treatment (post-combustion) technologies. Combustion control processes can reduce the quantity of NO_x formed during the combustion process. Post-combustion technologies reduce the NO_x concentrations in the flue gas steam after the NO_x has been formed in the combustion process. These methods may be used alone or in combination to achieve the various degrees of NO_x emissions required.

2.4.1.1 Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) systems are an add-on flue gas treatment (post-combustion control technology) to control NO_x emissions. The SCR process involves the injection of a nitrogen-based reducing agent (reagent) such as ammonia (NH_3) or urea (CON_2H_4) to reduce the NO_x in the flue gas to N_2 and H_2O. The reagent is injected into the flue gas prior to passage through a catalyst bed, which accelerates the NO_x reduction reaction rate. Use of SCR results in small levels of NH_3 emissions (NH_3 slip). As the catalyst degrades, NH_3 slip will increase, ultimately requiring catalyst replacement.

Many types of catalysts, ranging from active metals to highly porous ceramics, are available for different applications. The type of catalyst chosen depends on several operational parameters, such as reaction temperature range, flue gas flow rate, fuel chemistry, catalyst activity and selectivity, operating life, and cost. Catalyst materials include, platinum (Pt), vanadium (V), titanium (Ti), tungsten (W), titanium oxide (TiO_2), zirconium oxide (ZrO_2), vanadium pentoxide (V_2O_5), silicon oxide (SiO_2), and zeolites (crystalline alumina silicates).

SCR systems can utilize aqueous NH_3, anhydrous NH_3, or a urea solution to produce NH_3 on demand. Aqueous NH_3 is generally transported and stored in concentrations ranging from 19% to 30% and therefore requires more storage capacity than anhydrous NH_3. Anhydrous NH_3 is nearly 100% pure in concentration and is a gas at normal atmospheric temperature and pressure. Anhydrous NH_3 must be stored and transported under pressure and when stored in quantities greater than 10,000 pounds, is subject to Risk Management Planning (RMP) requirements (40 CFR 68). The urea solution (urea and water at approximately 32% concentration) is used to form NH_3 on demand for injection into the flue gas. Generally, a specifically designed duct and decomposition chamber with a small supplemental burner is used to provide an appropriate temperature window and residence time to decompose urea to NH_3 and isocyanic acid (HNCO). Application of urea-based SCR systems to industrial boilers is a relatively new practice that is still under development.

Several different SCR system configurations have been used on utility boilers and are theoretically possible for use on smaller industrial boilers. In a high-dust SCR system, the reactor is located downstream of the economizer and upstream of the air heater, FGD system, and particulate control device. Low-dust SCR systems locate the reactor downstream of a particulate control device where the flue gas is relatively dust-free. Tail-end SCR systems locate the reactor downstream from all air pollution control equipment where most flue gas constituents detrimental to the SCR catalyst have been removed. However, tail-end SCR systems can require reheating of the flue gas to minimize condensation, leading to corrosion problems.

2.4.1.2 Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) is another method of post-combustion control. Similar to SCR, the SNCR process involves the injection of a nitrogen-based reducing agent (reagent) such as ammonia (NH_3) or urea to reduce the NO_x in the flue gas to N_2 and H_2O. However, the SNCR process works without the use of a catalyst. Instead, the SNCR process occurs within a combustion unit, which acts as the reaction chamber. The heat from the boiler combustion process provides the energy for the NO_x reduction reaction. Flue gas temperatures in the range of 1,500 to 1,900 °F, along with adequate reaction time within this temperature range, are required for this technology. SNCR is currently being used for NO_x emission control on some utility boilers, and can achieve NO_x reduction efficiencies of up to 75%. However, in typical industrial applications SNCR provides 30% to 50% NO_x reduction.

2.4.1.3 Combustion Controls

Combustion controls such as flue gas recirculation (FGR), reducing air preheat temperature (RAP), oxygen trim (OT), low excess air (LEA), over-fire air (OFA), staged combustion air (SCA), and low NO_x burners (LNB), can be used to reduce NO_x emissions depending on the type of boiler, characteristics of fuel and method of firing. In practice, combustion controls have not provided the same degree of NO_x controls as provided by add-on post combustion control technologies, but are generally used in conjunction with add-on controls, such as SNCR, to increase the NO_x removal efficiency. The CRK boilers are currently equipped with modern OFA control systems.

2.4.2 NO_x Control Technology Effectiveness

Effectiveness is measured by the amount of NO_x removed by each control technology based on a comparison of the controlled emission rates to the baseline emission rates of the boilers. Table 6 provides a summary of the NO_x control technology effectiveness.

Table 6 – NO_x Control Technology Effectiveness.

Control Technology	Percent NO_x Reduction	Emission Rate (lb/MMBtu)	Annual Emissions (tpy)	Tons NO_x Removed (tpy)
Two Identical Boilers (EU001 & EU002)				
Baseline/OFA	0	0.33	209	NA
SCR	80	0.07	42	167
SNCR	30	0.23	146	63
Slightly Larger Boiler (EU003)				
Baseline/OFA	0	0.32	202	NA
SCR	80	0.06	40	162
SNCR	30	0.22	141	61

The lower control efficiencies of 80 and 30% anticipated for the SCR and SNCR systems, respectively, are based on the fact the CRK boilers are equipped with modern OFA control systems that work to reduce the starting NO_x concentration. Furthermore, the boilers have a smaller than typical furnace size for the type of coal combusted and flue gas flow rates that are higher than typical. This operational characteristic, when combined with frequent process load swings resulting from varying production demands, results in variable flue gas temperature ranges within the boiler furnace and presents difficulties with balancing reagent injection and maintaining consistent control.

2.4.3 Evaluation of Impacts

The following sections present a detailed evaluation of the impacts of employing the feasible control technologies to control NO_x emissions from the CRK boilers. The four factors assessed include: cost of compliance, energy, non-air quality environmental impacts and remaining useful life.

2.4.3.1 Cost of Compliance

Table 7 summarizes the capital and annual operating costs associated with retrofitting NO_x control systems to each of the identical smaller CRK boilers (EU001 and EU002). Table 8 summarizes the same costs, adjusted for the slightly larger boiler (EU003). Detailed cost estimates indicating data sources for each cost category have been included in Appendix A.

Table 7 – NO_x Cost of Compliance – EU001 & EU002 (per Boiler).

Description	Technology Option	
	SCR	SNCR
Emission Rate (lb/MMBtu)	0.07	0.23
Emission Reduction (tpy)	167	63
Capital Cost ($)	10,975,000	2,685,600
Direct Annual Cost ($)	107,900	46,800
Indirect Annual Cost ($)	1,504,500	384,000
Total Annualized Cost ($)	1,612,400	430,800
Cost Effectiveness, per Boiler ($/ton)	9,700	6,800

Table 8 – NO_x Cost of Compliance – EU003.

Description	Technology Option	
	OFA + SCR	OFA + SNCR
Emission Rate (lb/MMBtu)	0.06	0.22
Emission Reduction (tpy)	162	61
Capital Cost ($)	12,499,000	2,890,200
Direct Annual Cost ($)	121,500	52,500
Indirect Annual Cost ($)	1,713,300	413,400
Total Annualized Cost ($)	1,834,800	465,900
Cost Effectiveness ($/ton)	11,300	7,600

2.4.3.2 Energy Impact

The application of SCR and SNCR systems would result in energy penalties in the form of electricity demand for required operation of ancillary equipment such as reagent preparation and delivery, as well as additional backpressure on the exhaust system that results in decreased operational efficiency.

2.4.3.3 Non-Air Quality Environmental Impacts

SCR and SNCR both require some form of ammonia (NH_3) source for operation. This can be stored in liquid, solid or gas, and processed on site for use. Depending on quantities stored, risk management requirements may apply. Both system are also prone to NH_3 slip from unreacted NH_3. This will result in the emission of an additional pollutant.

2.4.3.4 Remaining Useful Life

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.

Appendix A

Cost Calculations

Dry FGD Capital Cost Summary

Description of Cost	**($)**[A]	**Remarks**
Direct Capital Costs		
Dry FGD Equipment[B]	2,654,500	Scaled Quote
Control/Instrumentation[C]	265,500	10% of Equipment Cost
Sales Tax	159,300	6% of Equipment Cost
Freight[C]	132,700	5% of Equipment Cost
Total Equipment Cost (TEC)	**3,212,000**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	2,730,200	Based on percentage of TEC: 12% Foundation & Supports, 40% Erection, 1% Electrical Installation, 30% Piping, 1% Painting, 1% Insulation
Site Preparation[D]	1,000,000	Estimated
Total Direct Investment (TDI)	6,942,200	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
Contingency	96,400	3% of TEC
Engineering	321,200	10% of TEC
Construction & Field Expense	321,200	10% of TEC
Contractor Fees	321,200	10% of TEC
Start-up Assistance	32,100	1% of TEC
Performance Test	32,100	1% of TEC
Total Indirect Investment (TII)	**1,124,200**	

Total Turnkey Cost (TTC)	**8,066,400**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor and scaled from similar projects.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

Dry FGD Fabric Filter Capital Cost Summary

Description of Cost	**($)[A]**	**Remarks**
Direct Capital Costs		
Dry FGD Equipment[B]	2,022,400	Scaled Quote
Control/Instrumentation[C]	202,200	10% of Equipment Cost
Sales Tax	121,300	6% of Equipment Cost
Freight[C]	101,100	5% of Equipment Cost
Total Equipment Cost (TEC)	**2,447,000**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	1,810,800	Based on percentage of TEC: 4% Foundation & Supports, 50% Erection, 8% Electrical Installation, 1% Piping, 4% Painting, 7% Insulation
Site Preparation[D]	1,000,000	Estimated
Total Direct Investment (TDI)	5,257,800	**TEC + TIC + Site Prep. = TDI**
Indirect Capital Cost [C]		
Contingency	73,400	3% of TEC
Engineering	244,700	10% of TEC
Construction & Field Expense	489,400	20% of TEC
Contractor Fees	244,700	10% of TEC
Start-up Assistance	24,500	1% of TEC
Performance Test	24,500	1% of TEC
Total Indirect Investment (TII)	**1,101,200**	
Total Turnkey Cost (TTC)	**6,359,000**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor and scaled from similar projects.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

Dry FGD/Fabric Filter Annual Cost Summary

Description of Cost	($)[A]	Remarks
Direct Annual Costs [B]		
Dry FGD Labor	49,300	1 hr per shift, assumed 8 hr shifts
Dry FGD Supervisor	7,400	15% of labor
Fabric Filter Labor	65,700	2 hr per shift, assumed 8 hr shifts
Fabric Filter Supervisor	9,900	15% of labor
Solvent (Reagent)	256,400	Consumption x cost
Fabric Filter Bag Replacement	170,700	Labor plus bag cost
Solids Scrubber Disposal	56,200	Production x cost
Solids Fly Ash Disposal	94,100	Production x cost
Maintenance Labor, Dry FGD	49,300	1 hr per shift, assumed 8 hr shifts
Maintenance Material, Dry FGD	49,300	100% of labor
Maintenance Labor, Fabric F.	65,700	2 hr per shift, assumed 8 hr shifts
Maintenance Material, Fabric F.	65,700	100% of labor
Induced Draft Fan	129,400	Consumption x cost
Pump	42,900	Consumption x cost
Direct Annual Costs (DAC)	**1,112,000**	

Indirect Annual Costs [C]		
Overhead	473,600	60% of O&M Labor
Administrative Charges	288,500	2% of Total Capital Investment
Property Taxes	144,300	1% of Total Capital Investment
Insurance	144,300	1% of Total Capital Investment
Dry FGD Annualized Costs[D]	885,600	(Capital Investment) x (CFR of 0.10979)
Fabric Filter Annualized Costs[E]	600,200	(Capital Investment) x (CFR of 0.09439)
Indirect Annual Costs (IAC)	**2,536,500**	

Total Annualized Costs (TAC)	**3,648,500**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs are based on site-specific design parameters.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers and fabric filters.

[D] Capital Recovery Factor (CFR) based on 15 year life and an interst rate of 7%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

[E] Capital Recovery Factor (CFR) based on 20 year life and an interst rate of 7%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

Dry Sorbent Injection Capital Cost Summary

Description of Cost	(\$)[A]	Remarks
Direct Capital Costs		
Dry FGD Equipment[B]	1,044,400	Vendor Quote
Control/Instrumentation[C]	104,400	10% of Equipment Cost
Sales Tax	62,700	6% of Equipment Cost
Freight[C]	52,200	5% of Equipment Cost
Total Equipment Cost (TEC)	**1,263,700**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	1,074,100	Based on percentage of TEC: 12% Foundation & Supports, 40% Erection, 1% Electrical Installation, 30% Piping, 1% Painting, 1% Insulation
Site Preparation[D]	250,000	Estimated (includes electrical upgrade)
Total Direct Investment (TDI)	2,587,800	**TEC + TIC + Site Prep. = TDI**

Description of Cost	(\$)[A]	Remarks
Indirect Capital Cost [C]		
Contingency	37,900	3% of TEC
Engineering	63,200	5% of TEC
Construction & Field Expense	126,400	10% of TEC
Contractor Fees	126,400	10% of TEC
Start-up Assistance	12,600	1% of TEC
Performance Test	12,600	1% of TEC
Total Indirect Investment (TII)	**379,100**	

Description of Cost	(\$)[A]	Remarks
Total Turnkey Cost (TTC)	**2,966,900**	**TDI + TII = TTC**

[A] Values rounded to the nearest \$100.

[B] Capital equipment cost provided by vendor.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

Dry Sorbent Injection Annual Cost Summary

Description of Cost	**($)[A]**	**Remarks**
Direct Annual Costs [B]		
DSI Labor	24,600	1/2 hr per shift, assumed 8 hr shifts
DSI Supervisor	3,700	15% of labor
Solvent (Trona)	30,800	Consumption x cost
Solids Fly Ash Disposal	15,100	Production x cost
Maintenance Labor	24,600	1/2 hr per shift, assumed 8 hr shifts
Maintenance Material, Dry FGD	24,600	100% of labor
Induced Draft Fan/Pumps	12,900	Consumption x cost
Direct Annual Costs (DAC)	**136,300**	

Indirect Annual Costs [C]		
Overhead	65,000	60% of O&M Labor
Administrative Charges	59,300	2% of Total Capital Investment
Property Taxes	29,700	1% of Total Capital Investment
Insurance	29,700	1% of Total Capital Investment
Dry FGD Annualized Costs[D]	325,700	(Capital Investment) x (CFR of 0.10979)
Indirect Annual Costs (IAC)	**509,400**	

Total Annualized Costs (TAC)	**645,700**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs are based on site-specific design parameters and vendor quote.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers and fabric filters.

[D] Capital Recovery Factor (CFR) based on 15 year life and an interst rate of 7%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

Selective Catalytic Reduction Capital Cost Summary

Description of Cost	($)[A]	Remarks
Direct Capital Costs		
SCR Equipment[B]	4,149,800	Control Cost Manual Spreadsheet
Reagent Preparation Cost[B]	1,545,200	Control Cost Manual Spreadsheet
Control/Instrumentation[C]	415,000	10% of Equipment Cost
Sales Tax	249,000	6% of Equipment Cost
Freight[C]	207,500	5% of Equipment Cost
Total Equipment Cost (TEC)	**6,566,500**	
Total Installation Cost (TIC)/Balance of Plant Cost[B]	1,872,800	Control Cost Manual Spreadsheet
Site Preparation[D]	500,000	Demo and Equipment Relocation
Total Direct Investment (TDI)	**8,939,300**	**TEC + TIC + Site Prep. = TDI**
Indirect Capital Cost [C]		
Contingency	197,000	3% of TEC
Engineering	656,700	10% of TEC
Construction & Field Expense	328,300	5% of TEC
Contractor Fees	656,700	10% of TEC
Start-up Assistance	131,300	2% of TEC
Performance Test	65,700	1% of TEC
Total Indirect Investment (TII)	**2,035,700**	
Total Turnkey Cost (TTC)	**10,975,000**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost obtained from EPA Air Pollution Control SCR Spreadsheet.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002.

[D] Estimated by HDR.

Selective Catalytic Reduction Annual Cost Summary

Description of Cost	($)[A]	Remarks
Direct Annual Costs [B]		
Annual SCR Maintenance	49,200	Control Cost Manual Spreadsheet
Reagent (Ammonia)	7,300	Control Cost Manual Spreadsheet
SCR Electricity	20,700	Control Cost Manual Spreadsheet
Catalyst Replacment	30,700	Control Cost Manual Spreadsheet
Direct Annual Costs (DAC)	**107,900**	

Indirect Annual Costs [C]		
Overhead	29,500	60% of O&M Labor
Administrative Charges	219,500	2% of Total Capital Investment
Property Taxes	109,800	1% of Total Capital Investment
Insurance	109,800	1% of Total Capital Investment
Dry FGD Annualized Costs[D]	1,035,900	(Capital Investment) x (CFR of 0.09439)
Indirect Annual Costs (IAC)	**1,504,500**	

Total Annualized Costs (TAC)	**1,612,400**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs obtained from EPA Air Pollution Control SCR Spreadsheet.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for incinerators and oxidizers.

[D] Capital Recovery Factor (CFR) based on 20 year life and an interst rate of 7%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

Selective Non-Catalytic Reduction Capital Cost Summary

Description of Cost	**($)**[A]	**Remarks**
Direct Capital Costs		
SNCR Equipment[B]	801,200	Control Cost Manual Spreadsheet
Control/Instrumentation[C]	80,100	10% of Equipment Cost
Sales Tax	48,100	6% of Equipment Cost
Freight[C]	40,100	5% of Equipment Cost
Total Equipment Cost (TEC)	**969,500**	
Total Installation Cost (TIC)/Balance of Plant Cost[B]	1,165,400	Control Cost Manual Spreadsheet
Site Preparation[D]	250,000	Demo and Equipment Relocation
Total Direct Investment (TDI)	**2,384,900**	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
Contingency	29,100	3% of TEC
Engineering	97,000	10% of TEC
Construction & Field Expense	48,500	5% of TEC
Contractor Fees	97,000	10% of TEC
Start-up Assistance	19,400	2% of TEC
Performance Test	9,700	1% of TEC
Total Indirect Investment (TII)	**300,700**	

Total Turnkey Cost (TTC)	**2,685,600**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost obtained from EPA Air Pollution Control SNCR Spreadsheet.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002.

[D] Estimated by HDR.

Selective Non-Catalytic Reduction Annual Cost Summary

Description of Cost	**($)[A]**	**Remarks**
Direct Annual Costs [B]		
Annual SNCR Maintenance	38,300	Control Cost Manual Spreadsheet
Reagent (Ammonia)	7,000	Control Cost Manual Spreadsheet
Electricity	400	Control Cost Manual Spreadsheet
Water	200	Control Cost Manual Spreadsheet
Additional Fuel	800	Control Cost Manual Spreadsheet
Additional Ash	100	Control Cost Manual Spreadsheet
Direct Annual Costs (DAC)	**46,800**	

Indirect Annual Costs [C]		
Overhead	23,000	60% of O&M Labor
Administrative Charges	53,700	2% of Total Capital Investment
Property Taxes	26,900	1% of Total Capital Investment
Insurance	26,900	1% of Total Capital Investment
Dry FGD Annualized Costs[D]	253,500	(Capital Investment) x (CFR of 0.09439)
Indirect Annual Costs (IAC)	**384,000**	

Total Annualized Costs (TAC)	**430,800**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs obtained from EPA Air Pollution Control SCR Spreadsheet.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for incinerators and oxidizers.

[D] Capital Recovery Factor (CFR) based on 20 year life and an interst rate of 7%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

Dry FGD Capital Cost Summary

Description of Cost	**($)**[A]	**Remarks**
Direct Capital Costs		
Dry FGD Equipment[B]	2,986,300	Scaled Quote
Control/Instrumentation[C]	298,600	10% of Equipment Cost
Sales Tax	179,200	6% of Equipment Cost
Freight[C]	149,300	5% of Equipment Cost
Total Equipment Cost (TEC)	**3,613,400**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	3,071,400	Based on percentage of TEC: 12% Foundation & Supports, 40% Erection, 1% Electrical Installation, 30% Piping, 1% Painting, 1% Insulation
Site Preparation[D]	1,000,000	Estimated
Total Direct Investment (TDI)	7,684,800	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
Contingency	108,400	3% of TEC
Engineering	361,300	10% of TEC
Construction & Field Expense	361,300	10% of TEC
Contractor Fees	361,300	10% of TEC
Start-up Assistance	36,100	1% of TEC
Performance Test	36,100	1% of TEC
Total Indirect Investment (TII)	**1,264,500**	

Total Turnkey Cost (TTC)	**8,949,300**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor and scaled from similar projects.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

Dry FGD Fabric Filter Capital Cost Summary

Description of Cost	**($)[A]**	**Remarks**
Direct Capital Costs		
Dry FGD Equipment[B]	2,275,200	Scaled Quote
Control/Instrumentation[C]	227,500	10% of Equipment Cost
Sales Tax	136,500	6% of Equipment Cost
Freight[C]	113,800	5% of Equipment Cost
Total Equipment Cost (TEC)	**2,753,000**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	2,037,200	Based on percentage of TEC: 4% Foundation & Supports, 50% Erection, 8% Electrical Installation, 1% Piping, 4% Painting, 7% Insulation
Site Preparation[D]	1,000,000	Estimated
Total Direct Investment (TDI)	5,790,200	**TEC + TIC + Site Prep. = TDI**
Indirect Capital Cost [C]		
Contingency	82,600	3% of TEC
Engineering	275,300	10% of TEC
Construction & Field Expense	550,600	20% of TEC
Contractor Fees	275,300	10% of TEC
Start-up Assistance	27,500	1% of TEC
Performance Test	27,500	1% of TEC
Total Indirect Investment (TII)	**1,238,800**	
Total Turnkey Cost (TTC)	**7,029,000**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor and scaled from similar projects.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

Dry FGD/Fabric Filter Annual Cost Summary

Description of Cost	($)[A]	Remarks
Direct Annual Costs [B]		
Dry FGD Labor	49,300	1 hr per shift, assumed 8 hr shifts
Dry FGD Supervisor	7,400	15% of labor
Fabric Filter Labor	65,700	2 hr per shift, assumed 8 hr shifts
Fabric Filter Supervisor	9,900	15% of labor
Solvent (Reagent)	288,500	Consumption x cost
Fabric Filter Bag Replacement	192,100	Labor plus bag cost
Solids Scrubber Disposal	63,200	Production x cost
Solids Fly Ash Disposal	105,800	Production x cost
Maintenance Labor, Dry FGD	49,300	1 hr per shift, assumed 8 hr shifts
Maintenance Material, Dry FGD	49,300	100% of labor
Maintenance Labor, Fabric F.	65,700	2 hr per shift, assumed 8 hr shifts
Maintenance Material, Fabric F.	65,700	100% of labor
Induced Draft Fan	145,600	Consumption x cost
Pump	48,300	Consumption x cost
Direct Annual Costs (DAC)	**1,205,800**	
Indirect Annual Costs [C]		
Overhead	505,700	60% of O&M Labor
Administrative Charges	319,600	2% of Total Capital Investment
Property Taxes	159,800	1% of Total Capital Investment
Insurance	159,800	1% of Total Capital Investment
Dry FGD Annualized Costs[D]	982,500	(Capital Investment) x (CFR of 0.10979)
Fabric Filter Annualized Costs[E]	663,500	(Capital Investment) x (CFR of 0.09439)
Indirect Annual Costs (IAC)	**2,790,900**	
Total Annualized Costs (TAC)	**3,996,700**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs are based on site-specific design parameters.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers and fabric filters.

[D] Capital Recovery Factor (CFR) based on 15 year life and an interst rate of 7%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

[E] Capital Recovery Factor (CFR) based on 20 year life and an interst rate of 7%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

Dry Sorbent Injection Capital Cost Summary

Description of Cost	**($)[A]**	**Remarks**
Direct Capital Costs		
Dry FGD Equipment[B]	1,175,000	Vendor Quote
Control/Instrumentation[C]	117,500	10% of Equipment Cost
Sales Tax	70,500	6% of Equipment Cost
Freight[C]	58,800	5% of Equipment Cost
Total Equipment Cost (TEC)	**1,421,800**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	1,208,500	Based on percentage of TEC: 12% Foundation & Supports, 40% Erection, 1% Electrical Installation, 30% Piping, 1% Painting, 1% Insulation
Site Preparation[D]	250,000	Estimated (includes electrical upgrade)
Total Direct Investment (TDI)	2,880,300	**TEC + TIC + Site Prep. = TDI**
Indirect Capital Cost [C]		
Contingency	42,700	3% of TEC
Engineering	71,100	5% of TEC
Construction & Field Expense	142,200	10% of TEC
Contractor Fees	142,200	10% of TEC
Start-up Assistance	14,200	1% of TEC
Performance Test	14,200	1% of TEC
Total Indirect Investment (TII)	**426,600**	
Total Turnkey Cost (TTC)	**3,306,900**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

Dry Sorbent Injection Annual Cost Summary

Description of Cost	**($)[A]**	**Remarks**
Direct Annual Costs [B]		
DSI Labor	24,600	1/2 hr per shift, assumed 8 hr shifts
DSI Supervisor	3,700	15% of labor
Solvent (Trona)	34,700	Consumption x cost
Solids Fly Ash Disposal	17,000	Production x cost
Maintenance Labor	24,600	1/2 hr per shift, assumed 8 hr shifts
Maintenance Material, Dry FGD	24,600	100% of labor
Induced Draft Fan/Pumps	14,500	Consumption x cost
Direct Annual Costs (DAC)	**143,700**	

Indirect Annual Costs [C]		
Overhead	67,300	60% of O&M Labor
Administrative Charges	66,100	2% of Total Capital Investment
Property Taxes	33,100	1% of Total Capital Investment
Insurance	33,100	1% of Total Capital Investment
Dry FGD Annualized Costs[D]	363,100	(Capital Investment) x (CFR of 0.10979)
Indirect Annual Costs (IAC)	**562,700**	

Total Annualized Costs (TAC)	**706,400**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs are based on site-specific design parameters and vendor quote.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers and fabric filters.

[D] Capital Recovery Factor (CFR) based on 15 year life and an interst rate of 7%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

Selective Catalytic Reduction Capital Cost Summary

Description of Cost	**($)[A]**	**Remarks**
Direct Capital Costs		
SCR Equipment[B]	4,954,500	Control Cost Manual Spreadsheet
Reagent Preparation Cost[B]	1,618,800	Control Cost Manual Spreadsheet
Control/Instrumentation[C]	495,500	10% of Equipment Cost
Sales Tax	297,300	6% of Equipment Cost
Freight[C]	247,700	5% of Equipment Cost
Total Equipment Cost (TEC)	**7,613,800**	
Total Installation Cost (TIC)/Balance of Plant Cost[B]	2,024,900	Control Cost Manual Spreadsheet
Site Preparation[D]	500,000	Demo and Equipment Relocation
Total Direct Investment (TDI)	**10,138,700**	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
Contingency	228,400	3% of TEC
Engineering	761,400	10% of TEC
Construction & Field Expense	380,700	5% of TEC
Contractor Fees	761,400	10% of TEC
Start-up Assistance	152,300	2% of TEC
Performance Test	76,100	1% of TEC
Total Indirect Investment (TII)	**2,360,300**	

Total Turnkey Cost (TTC)	**12,499,000**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost obtained from EPA Air Pollution Control SCR Spreadsheet.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002.

[D] Estimated by HDR.

Selective Catalytic Reduction Annual Cost Summary

Description of Cost	**($)[A]**	**Remarks**
Direct Annual Costs [B]		
Annual SCR Maintenance	55,900	Control Cost Manual Spreadsheet
Reagent (Ammonia)	9,700	Control Cost Manual Spreadsheet
SCR Electricity	27,600	Control Cost Manual Spreadsheet
Catalyst Replacment	28,300	Control Cost Manual Spreadsheet
Direct Annual Costs (DAC)	**121,500**	

Indirect Annual Costs [C]		
Overhead	33,500	60% of O&M Labor
Administrative Charges	250,000	2% of Total Capital Investment
Property Taxes	125,000	1% of Total Capital Investment
Insurance	125,000	1% of Total Capital Investment
Dry FGD Annualized Costs[D]	1,179,800	(Capital Investment) x (CFR of 0.09439)
Indirect Annual Costs (IAC)	**1,713,300**	

Total Annualized Costs (TAC)	**1,834,800**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs obtained from EPA Air Pollution Control SCR Spreadsheet.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for incinerators and oxidizers.

[D] Capital Recovery Factor (CFR) based on 20 year life and an interst rate of 7%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

Selective Non-Catalytic Reduction Capital Cost Summary

Description of Cost	($)[A]	Remarks
Direct Capital Costs		
SNCR Equipment[B]	866,300	Control Cost Manual Spreadsheet
Control/Instrumentation[C]	86,600	10% of Equipment Cost
Sales Tax	52,000	6% of Equipment Cost
Freight[C]	43,300	5% of Equipment Cost
Total Equipment Cost (TEC)	**1,048,200**	
Total Installation Cost (TIC)/Balance of Plant Cost[B]	1,267,100	Control Cost Manual Spreadsheet
Site Preparation[D]	250,000	Demo and Equipment Relocation
Total Direct Investment (TDI)	**2,565,300**	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
Contingency	31,400	3% of TEC
Engineering	104,800	10% of TEC
Construction & Field Expense	52,400	5% of TEC
Contractor Fees	104,800	10% of TEC
Start-up Assistance	21,000	2% of TEC
Performance Test	10,500	1% of TEC
Total Indirect Investment (TII)	**324,900**	

Total Turnkey Cost (TTC)	**2,890,200**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost obtained from EPA Air Pollution Control SNCR Spreadsheet.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002.

[D] Estimated by HDR.

Selective Non-Catalytic Reduction Annual Cost Summary

Description of Cost	($)[A]	Remarks
Direct Annual Costs [B]		
Annual SNCR Maintenance	41,600	Control Cost Manual Spreadsheet
Reagent (Ammonia)	9,000	Control Cost Manual Spreadsheet
Electricity	600	Control Cost Manual Spreadsheet
Water	200	Control Cost Manual Spreadsheet
Additional Fuel	1,000	Control Cost Manual Spreadsheet
Additional Ash	100	Control Cost Manual Spreadsheet
Direct Annual Costs (DAC)	**52,500**	
Indirect Annual Costs [C]		
Overhead	25,000	60% of O&M Labor
Administrative Charges	57,800	2% of Total Capital Investment
Property Taxes	28,900	1% of Total Capital Investment
Insurance	28,900	1% of Total Capital Investment
Dry FGD Annualized Costs[D]	272,800	(Capital Investment) x (CFR of 0.09439)
Indirect Annual Costs (IAC)	**413,400**	
Total Annualized Costs (TAC)	**465,900**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs obtained from EPA Air Pollution Control SCR Spreadsheet.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for incinerators and oxidizers.

[D] Capital Recovery Factor (CFR) based on 20 year life and an interst rate of 7%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

Regional Haze Four Factor Analysis

American Crystal Sugar Company

Crookston, MN

For Submittal to:
Minnesota Pollution Control Agency
520 Lafayette Road North
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Revised:
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Appendix A. Cost Calculations

1 Introduction

In response to the Minnesota Pollution Control Agency (MPCA) Request for Information (ROI) dated February 14, 2020 and the subsequent comments received by e-mail on March 8, 2021, American Crystal Sugar Company (ACSC) is providing the following revised Four Factor Analysis to address pollutants of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emitted from the coal-fired boilers at the Crookston (CRK) facility.

This analysis is being provided for planning purposes and is based on budgetary cost information obtained from scaled vendor quotes for similar systems as well as methodology presented in the U.S. Environmental Protection Agency's (EPA) Air Pollution Control Cost Manual. This approach is intended to provide a study-level estimate (+/-30%) of capital and annual costs. In the event that emission reductions will be proposed for inclusion in the State Implementation Plan (SIP), it is requested that ACSC be given the opportunity to further refine the cost data to incorporate site-specific quotes reflecting current market conditions and unique site physical constraints.

1.1 Analysis Methodology

Following the U.S. Environmental Protection Agency (EPA) *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 20, 2019, the Four Factor Analysis addresses:

- The costs of compliance;
- The time necessary for compliance;
- The energy and non-air quality environmental impacts of compliance; and,
- The remaining useful life of the source(s).

The first step in the process is identification of all available retrofit technologies for each pollutant (SO_2 and NO_x). Control options that are technically infeasible are eliminated and remaining options are evaluated to determine their control effectiveness and economic, energy and environmental impacts.

Technically feasible control technologies are ranked in the order of highest expected emission reduction to lowest expected emission reduction and are evaluated following a "top-down" approach similar to Best Available Control Technology (BACT) analyses.

Impacts considered for each control technology include: cost of compliance, energy impacts, non-air quality environmental impacts and the remaining useful life of the unit to be controlled.

1.2 CRK Source Parameters

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 electrostatic precipitators to control particulate matter emissions. Two of the boilers were originally constructed in the early 1950s and the third was constructed in the mid-1970s. The ESP systems were added in the mid-1970s when the third boiler was constructed. In 2014 all three boilers were modified to install new OFA systems to control carbon monoxide (CO) and NO_x emissions in advance of the forthcoming 40 CFR 63, Subpart DDDDD, industrial boiler national emission standards. Additionally, the ESP systems were extensively upgraded in 2013. Upgrades included the addition of a fourth collection field, flow modifications to better distribute flue gas flow, rebuilding of collection plates and electrodes, and upgrades to optimize power supplies and controls.

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. During normal operations, the boilers typically operate between 70 and 80 percent capacity depending on processing demands. 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). Given the campaign constraints, the typical annual heat input for each of the boilers is around 700,000 MMBtu/yr.

All three boilers combust low sulfur subbituminous coal from the Powder River Basin (PRB). 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.

The boilers are identified as EU001, EU002, and EU003 in Air Emission Permit No. 11900001-004. The operating permit limits each boiler to the maximum emission rates shown in Table 1 below.

Table 1 – Permitting Emission Limits.

Pollutant	Boiler 1 – EU001	Boiler 2 – EU002	Boiler 3 – EU003
SO_2	127 (0.93 lb/MMBtu)	127 lb/hr (0.93 lb/MMBtu)	154 lb/hr (0.93 lb/MMBtu)
NO_x	99.8 lb/hr (0.73 lb/MMBtu)	99.8 lb/hr (0.73 lb/MMBtu)	120 lb/hr (0.73 lb/MMBtu)

As indicated in the EPA's *Guidance on Regional Haze State Implementation Plans*, a state may use a source's annual emissions in tons to determine actual visibility impacts. Therefore, actual emission levels based on source test data were used to characterize emissions-related factors in this analysis. The average SO_2 emission rate from the two identical CRK boilers as reported in the most recent emission inventory is 0.37 lb/MMBtu and 241 tons per year (tpy) for each boiler. The SO_2 emission rate from the slightly larger boiler is 0.41 lb/MMBtu and 253 tpy. The average NO_x emission rate from the two identical CRK boilers as reported in the most recent emission inventory is 0.33 lb/MMBtu and 209 tpy for each boiler. The NO_x emission rate from the slightly larger boiler is 0.32 lb/MMBtu and 202 tpy.

Because two of the boilers are of identical size and type, control technology costs and design features would be the same for both boilers. The third boiler is of the same type, but slightly larger. It is anticipated that the Four Factor Analysis applies to the CRK facility as a whole, and two potential control technology determinations could be made: one for the identical boilers, and one for the slightly larger single boiler at the facility. The average emission rate for the two identical boilers was used in the analysis to determine costs of compliance for those units and the individual emission rate was used for the slightly larger boiler.

2 Four Factor Analysis

2.1 Applicable Pollutants

The Four Factor Analysis addresses criteria pollutants of SO_2 and NO_x.

SO_2 Formation. SO_2 emissions are formed from the oxidation of organic sulfur and pyritic sulfur in the coal during the combustion process. The majority of sulfur is oxidized to SO_2, however, a small quantity may be further oxidized to form sulfur trioxide (SO_3). Approximately 90% of the sulfur present in the subbituminous coal will be emitted as sulfur oxides (SO_x) compounds. Alkaline ash from some coals (including PRB coals) may cause some of the sulfur to react in the furnace to form various sulfate salts that are then retained in the fly ash. Sulfuric acid mist (H_2SO_4) forms when SO_2 emissions react with moisture and oxygen in the environment.

NO_x Formation. There are two primary mechanisms of NO_x formation in coal-fired industrial boilers: thermal production of NOx from atmospheric nitrogen and oxygen, and oxidation of nitrogen bound in the fuel. High combustion temperatures cause the nitrogen (N_2) and oxygen (O_2) molecules in the combustion air to react and form thermal NO_x. Because thermal NO_x is primarily a function of combustion temperature, NO_x emission rates vary with burner and source design. Experimental measurements of thermal NO_x formation have shown that the NO_x concentration is exponentially dependent on temperature and is proportional to the N_2 concentration in the flame, the square root of the O_2 concentration in the flame, and the gas residence time[1]. The formation of fuel NO_x from reactions of fuel bound nitrogen and air can account for up to 80% of total NO_x from coal combustion. Subbituminous coals contain from 0.5 to 2 percent by weight fuel-bound nitrogen.

2.2 Economic Evaluation Criteria

Costs of compliance are directly related to the technically feasible control technology option selected and the level of emission reduction experienced from the control. Costs are expressed in terms of dollars per ton of pollutant removed, where the cost is the annualized capital and

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[1] AP42, Chapter 1, Bituminous and Subbituminous Coal Combustion, (9/98).

operating costs, and the tons of pollutant removed is the incremental reduction in pollutant emissions over current baseline (actual) emission levels.

Base economic criteria used in this analysis are listed in Table 2.

Table 2 – Economic Evaluation Criteria.

Economic Parameter	Value
Interest Rate, percent	5[A]
Control Equipment Economic Life, years	20[B]
Base Labor Cost, $/hr	60[C]
Energy Cost, $/kW-hr	0.06[D]

[A] Current ACSC rate for capital improvement project financing.
[B] EPA Memorandum, Calculating Amortized Capital Costs, July 24, 1987, Robert D. Bauman, Chief, Standards and Implementation Branch.
[C] Loaded labor rate obtained from ACSC.
[D] Actual ACSC electricity cost.

Cost estimates used in the analysis have been compile from a number of data sources. In general, the cost estimates were performed following guidance provided in the EPA Air Pollution Control Cost Manual, Seventh Edition, January 2017. The EPA control cost manual data was supplemented with vendor supplied quotations when available and general engineering estimates. Detailed cost estimate and support data have been provided in Appendix A.

2.3 SO_2 Analysis

Because two of the coal-fired boilers at the CRK facility are identical, the analysis was prepared for one individual boiler at that capacity. The results of the analysis can be applied equally to each boiler. A separate analysis was performed for the third, slightly larger boiler.

2.3.1 Identification of SO_2 Control Technologies

Control of SO_2 emissions from fuel-combustion sources can be accomplished through two approaches: removal of elemental sulfur from the fuel prior to combustion, and flue gas desulfurization (FGD), which consists of removal of SO_2 from flue gas after combustion (post-combustion control).

Many oil refineries operate catalyst-based desulfurization units to remove organic sulfur from liquid crude oil. However, in solid fuels, such as coal, a significant fraction of the sulfur is in the form of pyrite (FeS_2) or other mineral sulfates. It is possible to remove some mineral sulfates through physical processes such as washing and/or chemical processing. However, desulfurization of solid fuels is generally viewed as inefficient and expensive. Additionally, organic sulfur cannot be removed by physical cleaning. It is unlikely that sufficient desulfurization of solid fuels can be accomplished to meet anticipated emission requirements. Therefore removal of sulfur from the coal prior to combustion will not be considered a viable option for this analysis.

FGD technologies can be divided into two main categories: regenerative and throwaway processes. Regenerative processes recover sulfur in a usable form that can be sold as a reusable sulfur product. Throwaway processes remove sulfur from flue gas and scrubber byproducts are subsequently discarded. All of the FGD technologies considered can achieve SO_2 removal efficiencies of 90 to 95% depending on the amount of sulfur in the coal. For relatively high sulfur coals, removal efficiencies can exceed 95%, while for lower sulfur coals (such as PRB), the achievable removal efficiency is typically less than 95%.

Regenerative processes, by nature, contain a regeneration step in the FGD process that results in higher costs than throwaway processes due to equipment and operation expenses. However, in instances where disposal options are limited and markets for recovered sulfur products are readily available, regenerative processes may be used. Potential regenerative processes that are available include the Wellman-Lord (W-L) process, magnesium oxide process, citrate scrubbing process, Flakt-Boliden process, aqueous carbonate process, Sulf-X process, Conosox process, Westvaco process and adsorption of SO_2 by a bed of copper oxide.

Throwaway processes such as limestone scrubbing have become widely accepted by the coal-fired power industry for FGD because limestone scrubbers have overall lower costs and are simpler to operate than regenerative processes. Because the throwaway process can achieve the same removal efficiencies as regenerative processes and cost less, this analysis for SO_2 will focus on throwaway processes and further discussion of regenerative processes will not be considered.

Throwaway processes can be divided into two categories, wet and dry. Wet or dry refers to the state of the waste by-products. Both wet and dry technologies have advantages and disadvantages with respect to initial capital and operational expenses.

2.3.1.1 Wet FGD Systems

Wet scrubbing (wet FGD) systems used for SO_2 reduction typically consist of the following operations: scrubbing or absorption, lime handling and slurry preparation, sludge processing, and flue gas handling.

Wet FGD technology is a well-established process for removing SO_2 from flue gas. In wet scrubbers, the flue gas enters a spray tower or absorber where it is sprayed with a water slurry, which is approximately 10 percent lime or limestone. Sodium alkali solutions can also be used in FGD systems, however these processes are considerably more expensive than lime. The preferred sorbents are limestone and lime, respectively, due to the availability and relatively low cost of limestone. Calcium in the slurry reacts with the SO_2 in the flue gas to form calcium sulfite or calcium sulfate. The overall chemical reaction can be simply expressed as:

$$SO_2 + CaCO_3 \rightarrow CaSO_3 + CO_2$$

Spent slurry from the reaction tank is pumped into a thickener where solids settle before being filtered for final dewatering to approximately 50 percent solids. Water removed during this process is sent to a process water holding tank, which eventually will require wastewater treatment. In a non-regenerative system, the waste sludge must also be disposed of properly.

Finally, scrubbed flue gases are directed through a stack gas reheater in order to minimize corrosion downstream of the scrubber due to conversion of SO_2 to SO_3 and subsequently sulfuric acid (H_2SO_4). Reheating is sometimes needed for proper drafting and rise of exhaust gases out the stack, as well as minimizing condensation. As an alternative, the stack can be constructed of acid resistant material.

Most wet FGD systems have two stages: one for fly ash removal and one for SO_2 removal. The flue gas normally passes first through a fly ash removal device, either an electrostatic precipitator (ESP) or a bag filter, and then into the SO_2 absorber. There are many different types of absorbers that can be used in wet FGD systems, including: spray towers, venturis, plate towers, and mobile packed beds. However, many of these systems can result in scale buildup, plugging or erosion, which can affect the dependability and efficiency of the absorber. Therefore, simple scrubbers such as spray towers are commonly used. The chief drawback of the spray tower design is that it requires a higher liquid-to-gas ratio for equivalent removal of SO_2 than other absorber designs.

2.3.1.2 Dry FGD Systems

In contrast to wet scrubbing systems, dry FGD (spray dryer) systems use much smaller amounts of liquid. With a spray dryer system, the flue gases enter an absorbing tower (dryer) where the hot gases are contacted with a finely atomized slurry, which is usually a calcium-based sorbent such as calcium hydroxide or calcium oxide (lime). Acid gases and SO_2 are absorbed by the slurry mixture and react to form solid salts. The heat of the flue gas evaporates the water droplets in the sprayed slurry, and a non-saturated flue gas exits the absorber tower. The absorption process is also somewhat temperature dependent. Cooler flue gases allow the acid gases to more effectively react with the sorbents. The overall chemical reactions can be simply expressed as:

$$Ca(OH)_2 + SO_2 \rightarrow CaSO_3(s) + H_2O$$

$$Ca(OH)_2 + 2HCl \rightarrow CaCl_2\ (s) + 2H_2O$$

As can be seen above, one mole of calcium hydroxide will neutralize one mole of SO_2, whereas one mole of calcium hydroxide will neutralize two moles of hydrochloric acid (HCl). A similar reaction occurs with the neutralization of hydrofluoric acid (HF). These reactions demonstrate that when using a spray dryer the HCl and HF are removed more readily than SO_2. Reagent requirements should consider that the HCl and HF are removed first, followed by the reagent quantity required to remove the SO_2[2].

The heat of the flue gas evaporates the water droplets in the sprayed slurry, and a non-saturated flue gas exists the absorber tower. The exhaust stream exiting the absorber contains fly ash, calcium salts, and un-reacted lime, which must be sent to a particulate control device such as a fabric filter (baghouse). The particulate control device not only is necessary to control particulate matter, but also aids in acid-gas removal. Acid gases are removed when the flue gas comes in contact with the lime-containing particles on the surface of the ESP or baghouse.

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[2] Karl B. Schnelle, Jr. and Charles A. Brown, Air Pollution Control Technology Handbook, CRC Press, 2002.

Fabric filters are considered to have slightly higher residual acid gas removal levels than ESPs because the acid gases must pass through the lime-containing filter cake in a fabric filter system. Modern dry FGD systems include a loop to recycle a portion of the baghouse-collected material for re-use in the FGD module because this material contains a relatively high amount of unreacted lime.

A lower efficiency Dry FGD process that utilizes either wet or dry reagent injected directly into the furnace or flue gas duct is known as dry sorbent injection (DSI). In general, hydrated lime, lime slurry or powdered lime is injected into the existing furnace or ductwork. The constraints of the existing furnace and ductwork configuration may limit expected retrofit control efficiencies of SO_2, which range from 50 to 80%. A significant drawback of this type of system is the increased maintenance costs incurred from directly injecting a sorbent into the furnace and associated duct work and the potential to significantly reduce the useful life of the boiler. Although DSI is a type of Dry FGD process, it will be referred to separately in this analysis.

2.3.2 SO_2 Control Technology Effectiveness

Effectiveness is measured by the amount of SO_2 removed from each control technology based on a comparison of the controlled emission rates to the baseline emission rates of the boilers. Table 3 provides a summary of the SO_2 control technology effectiveness.

Table 3 – SO_2 Control Technology Effectiveness.

Control Technology	Percent SO_2 Reduction[A]	Emission Rate (lb/MMBtu)	Annual Emissions (tpy)	Tons SO_2 Removed (tpy)
Two Identical Boilers (EU001 & EU002)				
Baseline	0	0.37	241	NA
Wet FGD	90	0.04	24	217
Dry FGD	85	0.06	36	205
DSI	50	0.20	121	120
Slightly Larger Boiler (EU003)				
Baseline	0	0.41	253	NA
Wet FGD	90	0.04	25	228
Dry FGD	85	0.06	38	215
DSI	50	0.20	127	126

[A] Control efficiency is the lowest expected end of the range due to the combustion of low sulfur PRB coals and high relative flue gas flowrate for boiler design.

As indicated in Table 3, it is anticipated that nearly the same level of SO_2 control can be achieved by the use of either Dry or Wet FGD spray dryer systems (non-DSI). This assumption is based on observation of FGD control in use on coal-fired utility boilers.

In general terms, removal of high concentrations of SO_2 in the flue gas is easily accomplished using either Dry or Wet FGD. Lower concentrations become more difficult to control and require greater amounts of reagent. Historically, Wet FGD systems have been used on higher-sulfur eastern coals, leading to higher efficiencies cited for Wet FGD systems, given there is much more sulfur to control. However, on lower-sulfur western coals (such as the PRB coal used at CRK) modern Dry FGD systems with better atomizer systems in conjunction with modern fabric filter technology can perform as well as Wet FGD systems. Much of the final SO_2 control in a Dry FGD system takes place in the reagent-rich filter cake on the fabric filter.

Because of the equivalency in anticipated SO_2 emission rates, only Dry FGD technology is considered in this analysis. Dry FGD technology was selected as it has lower capital and operating costs than Wet FGD and will result in a more cost-effective approach. Wet FGD systems have been historically used on large sources greater than 3,000 MMBtu/hr (EPA Fact Sheet, EPA-452/F-03-034). On larger systems, the greater capital and operating costs can be more easily justified due to the greater mass of pollutants removed. Additional equipment such as water/slurry handling, slaking, waste handling, reaction chamber size, stack flue gas reheating and corrosive resistant materials, contribute to the higher capital equipment costs for Wet FGD systems.

Furthermore, use of Wet FGD to control SO_2 emissions from the CRK boilers would result in both higher energy penalties to the facility operations and the generation of more waste byproducts than would Dry FGD. Increased energy penalties would be due to the additional pumps and water handling equipment required for slurry preparation for the Wet FGD, which would also lead to the creation of additional waste byproducts from the spent slurry. Dewatering of the spent slurry results in the production of a wastewater stream, as well as a waste sludge that must be disposed of in a landfill. Dry FGD results only in a dry product which is easily landfilled.

The lower control efficiency of 50% anticipated for the DSI system is based on the fact the CRK boilers combust low sulfur PRB coal and have relatively high flue gas flow rates associated with the OFA system, resulting in lower starting SO_2 concentrations. Additionally, the boilers were originally designed to burn lignite coal, but were switched to subbituminous coal in the mid-1980s. As a result, the boilers have a smaller than typical furnace size for the type of coal combusted. This leads to higher combustion air flowrates, short residence times in the furnace, and boiler slagging and maintenance issues. The introduction of large amounts of sorbent into the furnace and high temperature flue gas (such as with DSI systems) is anticipated to magnify these issues and result in a detrimental impact on operation and efficiency. Furthermore, frequent process load swings resulting from varying production demands presents difficulties with balancing sorbent injection and maintaining consistent control.

2.3.3 Evaluation of Impacts

The following sections present a detailed evaluation of the impacts of employing Dry FGD and DSI to control SO_2 emissions from the CRK boilers. The four factors assessed include: cost of compliance, energy, non-air quality environmental impacts and remaining useful life.

2.3.3.1 Cost of Compliance

Table 3 summarizes the capital and annual operating costs associated with retrofitting a Dry FGD and DSI system to each of the identical smaller CRK boilers (EU001 and EU002). Table 5 summarizes the same costs, adjusted for the slightly larger boiler (EU003). Detailed cost estimates indicating data sources for each cost category have been included in Appendix A.

Table 4 – SO_2 Costs of Compliance – EU001 & EU002 (per Boiler).

Description	**Technology Option**	
	Dry FGD w/Fabric Filter	**DSI**
Emission Rate (lb/MMBtu)	0.06	0.20
Emission Reduction (tpy)	205	120
Capital Cost ($)	15,388,300	2,318,900
Direct Annual Cost ($)	1,112,000	136,300
Indirect Annual Cost ($)	2,351,600	348,100
Total Annualized Cost ($)	3,463,600	484,800
Cost Effectiveness, per Boiler ($/ton)	16,900	4,000

Table 5 – SO_2 Costs of Compliance – EU003.

Description	**Technology Option**	
	Dry FGD w/Fabric Filter	**DSI**
Emission Rate (lb/MMBtu)	0.06	0.20
Emission Reduction (tpy)	215	126
Capital Cost ($)	17,192,000	2,154,700
Direct Annual Cost ($)	1,205,800	143,700
Indirect Annual Cost ($)	2,603,700	383,000
Total Annualized Cost ($)	3,809,500	526,700
Cost Effectiveness ($/ton)	17,700	4,200

2.3.3.2 Energy Impact

Use of Dry FGD or DSI to control SO_2 emissions from the CRK boilers would result in energy penalties to facility operations in the form of the electricity demand required for operation of ancillary equipment such as the reagent preparation and atomizer equipment, as well as additional backpressure on the exhaust system that results in decreased operational efficiency.

2.3.3.3 Non-Air Quality Environmental Impacts

The primary detrimental non-air quality environmental impact of a Dry FGD or DSI system is the creation of a solid waste byproduct from the spent reagent. Unlike Wet FGD, there is no wastewater stream resultant from the use of Dry FGD. The solid waste that is produced from a Dry FGD system can be landfilled or possibly used as an agricultural soil supplement depending on the fly ash content.

The DSI system is anticipated to greatly increase maintenance requirements as a result of increased boiler slagging and equipment fouling. Given the age of the existing boilers, the implementation of such a system may have a significant negative impact on remaining useful life.

2.3.3.4 Remaining Useful Life

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.

2.4 NO_x Analysis

Because two of the coal-fired boilers at the CRK facility are identical, the analysis was prepared for one individual boiler at that capacity. The results of the analysis can be applied equally to each boiler. A separate analysis was performed for the third, slightly larger boiler.

2.4.1 Identification of NOx Control Technologies

Control of NO_x emissions from boilers can be attained through either the application of combustion controls or flue gas treatment (post-combustion) technologies. Combustion control processes can reduce the quantity of NO_x formed during the combustion process. Post-combustion technologies reduce the NO_x concentrations in the flue gas steam after the NO_x has been formed in the combustion process. These methods may be used alone or in combination to achieve the various degrees of NO_x emissions required.

2.4.1.1 Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) systems are an add-on flue gas treatment (post-combustion control technology) to control NO_x emissions. The SCR process involves the injection of a nitrogen-based reducing agent (reagent) such as ammonia (NH_3) or urea (CON_2H_4) to reduce the NO_x in the flue gas to N_2 and H_2O. The reagent is injected into the flue gas prior to passage through a catalyst bed, which accelerates the NO_x reduction reaction rate. Use of SCR results in small levels of NH_3 emissions (NH_3 slip). As the catalyst degrades, NH_3 slip will increase, ultimately requiring catalyst replacement.

Many types of catalysts, ranging from active metals to highly porous ceramics, are available for different applications. The type of catalyst chosen depends on several operational parameters, such as reaction temperature range, flue gas flow rate, fuel chemistry, catalyst activity and selectivity, operating life, and cost. Catalyst materials include, platinum (Pt), vanadium (V), titanium (Ti), tungsten (W), titanium oxide (TiO_2), zirconium oxide (ZrO_2), vanadium pentoxide (V_2O_5), silicon oxide (SiO_2), and zeolites (crystalline alumina silicates).

SCR systems can utilize aqueous NH_3, anhydrous NH_3, or a urea solution to produce NH_3 on demand. Aqueous NH_3 is generally transported and stored in concentrations ranging from 19% to 30% and therefore requires more storage capacity than anhydrous NH_3. Anhydrous NH_3 is nearly 100% pure in concentration and is a gas at normal atmospheric temperature and pressure. Anhydrous NH_3 must be stored and transported under pressure and when stored in quantities greater than 10,000 pounds, is subject to Risk Management Planning (RMP) requirements (40 CFR 68). The urea solution (urea and water at approximately 32% concentration) is used to form NH_3 on demand for injection into the flue gas. Generally, a specifically designed duct and decomposition chamber with a small supplemental burner is used to provide an appropriate temperature window and residence time to decompose urea to NH_3 and isocyanic acid (HNCO). Application of urea-based SCR systems to industrial boilers is a relatively new practice that is still under development.

Several different SCR system configurations have been used on utility boilers and are theoretically possible for use on smaller industrial boilers. In a high-dust SCR system, the reactor is located downstream of the economizer and upstream of the air heater, FGD system, and particulate control device. Low-dust SCR systems locate the reactor downstream of a particulate control device where the flue gas is relatively dust-free. Tail-end SCR systems locate the reactor downstream from all air pollution control equipment where most flue gas constituents detrimental to the SCR catalyst have been removed. However, tail-end SCR systems can require reheating of the flue gas to minimize condensation, leading to corrosion problems.

2.4.1.2 Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) is another method of post-combustion control. Similar to SCR, the SNCR process involves the injection of a nitrogen-based reducing agent (reagent) such as ammonia (NH_3) or urea to reduce the NO_x in the flue gas to N_2 and H_2O. However, the SNCR process works without the use of a catalyst. Instead, the SNCR process occurs within a combustion unit, which acts as the reaction chamber. The heat from the boiler combustion process provides the energy for the NO_x reduction reaction. Flue gas temperatures in the range of 1,500 to 1,900 °F, along with adequate reaction time within this temperature range, are required for this technology. SNCR is currently being used for NO_x emission control on some utility boilers, and can achieve NO_x reduction efficiencies of up to 75%. However, in typical industrial applications SNCR provides 30% to 50% NO_x reduction.

2.4.1.3 Combustion Controls

Combustion controls such as flue gas recirculation (FGR), reducing air preheat temperature (RAP), oxygen trim (OT), low excess air (LEA), over-fire air (OFA), staged combustion air (SCA), and low NO_x burners (LNB), can be used to reduce NO_x emissions depending on the type of boiler, characteristics of fuel and method of firing. In practice, combustion controls have not provided the same degree of NO_x controls as provided by add-on post combustion control technologies, but are generally used in conjunction with add-on controls, such as SNCR, to increase the NO_x removal efficiency. The CRK boilers are currently equipped with modern OFA control systems.

As indicated previously, all three boilers were modified in 2014 to install new OFA systems to control carbon monoxide (CO) and NO_x emissions in advance of the forthcoming 40 CFR 63, Subpart DDDDD, industrial boiler national emission standards. The modifications included upgrades to the underthrow feed systems to better distribute fuel and provide for consistent grate temperature and fuel management, installation of new overfire air supply fans and overfire air ducts and injection systems. Additionally, the boilers are equipped with automated oxygen trim systems to manage the combustion process. As a result of these modifications, CO and NO_x emissions have been optimized and represent the state-of-the-art with regard to available combustion management for the design/style of the boilers. Therefore, combustion controls is considered the base emission case for the four factor analysis.

2.4.2 NO_x Control Technology Effectiveness

Effectiveness is measured by the amount of NO_x removed by each control technology based on a comparison of the controlled emission rates to the baseline emission rates of the boilers. Table 6 provides a summary of the NO_x control technology effectiveness.

Table 6 – NO_x Control Technology Effectiveness.

Control Technology	Percent NO_x Reduction	Emission Rate (lb/MMBtu)	Tons NO_x Removed[a] (tpy)
Two Identical Boilers (EU001 & EU002)			
Baseline/OFA	0	0.33	NA
SCR	80	0.07	91
SNCR	30	0.23	25
Slightly Larger Boiler (EU003)			
Baseline/OFA	0	0.32	NA
SCR	80	0.06	109
SNCR	30	0.22	30

[a] Tons of NO_x removed from CCM SCR and SNCR spreadsheet.

The lower control efficiencies of 80 and 30% anticipated for the SCR and SNCR systems, respectively, are based on the fact the CRK boilers are equipped with modern OFA control systems that work to reduce the starting NO_x concentration. Furthermore, the boilers have a smaller than typical furnace size for the type of coal combusted and flue gas flow rates that are higher than typical. This operational characteristic, when combined with frequent process load swings resulting from varying production demands, results in variable flue gas temperature ranges within the boiler furnace and presents difficulties with balancing reagent injection and maintaining consistent control.

2.4.3 Evaluation of Impacts

The following sections present a detailed evaluation of the impacts of employing the feasible control technologies to control NO_x emissions from the CRK boilers. The four factors assessed include: cost of compliance, energy, non-air quality environmental impacts and remaining useful life.

2.4.3.1 Cost of Compliance

Table 7 summarizes the capital and annual operating costs associated with retrofitting NO_x control systems to each of the identical smaller CRK boilers (EU001 and EU002). Table 8 summarizes the same costs, adjusted for the slightly larger boiler (EU003). The costs were obtained from the CCM SCR and SNCR spreadsheets. Detailed cost estimates indicating data sources for each cost category have been included in Appendix A.

Table 7 – NO_x Cost of Compliance – EU001 & EU002 (per Boiler).

Description	**Technology Option**	
	SCR	**SNCR**
Emission Rate (lb/MMBtu)	0.07	0.23
Emission Reduction (tpy)	91	25
Capital Cost ($)	14,757,119	3,834,812
Total Annualized Cost ($)	1,328,167	377,379
Cost Effectiveness, per Boiler ($/ton)	14,657	14,914

Table 8 – NO_x Cost of Compliance – EU003.

Description	**Technology Option**	
	OFA + SCR	**OFA + SNCR**
Emission Rate (lb/MMBtu)	0.06	0.22
Emission Reduction (tpy)	109	30
Capital Cost ($)	16,766,382	4,160,084
Total Annualized Cost ($)	1,504,442	410,268
Cost Effectiveness ($/ton)	13,785	13,462

2.4.3.2 Energy Impact

The application of SCR and SNCR systems would result in energy penalties in the form of electricity demand for required operation of ancillary equipment such as reagent preparation and delivery, as well as additional backpressure on the exhaust system that results in decreased operational efficiency.

2.4.3.3 Non-Air Quality Environmental Impacts

SCR and SNCR both require some form of ammonia (NH_3) source for operation. This can be stored in liquid, solid or gas, and processed on site for use. Depending on quantities stored, risk management requirements may apply. Both system are also prone to NH_3 slip from unreacted NH_3. This will result in the emission of an additional pollutant.

2.4.3.4 Remaining Useful Life

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.

Appendix A

Cost Calculations

CRK No. 1 Dry FGD Capital Cost Summary

Description of Cost	(\$)[A]	Remarks
Direct Capital Costs		
Dry FGD Equipment[B]	3,014,251	Scaled Quote
Control/Instrumentation[C]	301,400	10% of Equipment Cost
Sales Tax	180,900	6% of Equipment Cost
Freight[C]	150,700	5% of Equipment Cost
Total Equipment Cost (TEC)	**3,647,300**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	3,100,200	Based on percentage of TEC: 12% Foundation & Supports, 40% Erection, 1% Electrical Installation, 30% Piping, 1% Painting, 1% Insulation
Retrofit Cost Adjustments [D]		
Infrastructure Relocation/Demolition	138,500	Estimated by HDR
Exhaust Stack	97,300	Estimated by HDR
Retrofit Cost Addition	182,700	Estimated by HDR
Total Direct Investment (TDI)	7,166,000	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
Contingency	109,400	3% of TEC
Engineering	364,700	10% of TEC
Construction & Field Expense	364,700	10% of TEC
Contractor Fees	364,700	10% of TEC
Start-up Assistance	36,500	1% of TEC
Performance Test	36,500	1% of TEC
Total Indirect Investment (TII)	**1,276,500**	

Total Turnkey Cost (TTC)	**8,442,500**	**TDI + TII = TTC**

[A] Values rounded to the nearest \$100.

[B] Capital equipment cost provided by vendor, scaled for capacity and ajdusted to 2019 dollars:
Capacity scaled using $C_n=r^{0.6}C$, Chemical Engineers' Handbook, Fifth Edition.

Alstom Sept. 2006
SDA System and Pulse Jet Fabric Filter Baghouse
\$43,000,000 Total
2 SDA vessels (66' dia. X 52' side height)
Support Steel, roof penthouse
3 rotary atomizers per vessel
Lime prep system - lime silos, lakers, pumps, controls
Pulse jet fabric filter, including pulse systrem, support steel, roof penthouse
2 350-hp rotary screw air compressors, 3800 gal air receiver, air dryrers, filters
No erection or installation
No piping or insulation

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

CRK No. 1 Dry FGD Fabric Filter Capital Cost Summary

Description of Cost	**($)**[A]	**Remarks**
Direct Capital Costs		
Fabric Filter Equipment[B]	2,621,088	Scaled Quote
Control/Instrumentation[C]	262,100	10% of Equipment Cost
Sales Tax	157,300	6% of Equipment Cost
Freight[C]	131,100	5% of Equipment Cost
Total Equipment Cost (TEC)	**3,171,600**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	2,347,000	Based on percentage of TEC: 4% Foundation & Supports, 50% Erection, 8% Electrical Installation, 1% Piping, 4% Painting, 7% Insulation
Retrofit Cost Adjustments [D]		
Infrastructure Relocation/Demolition	-	Included in SDA Costs
Exhaust Stack	-	Included in SDA Costs
Retrofit Cost Addition	-	Included in SDA Costs
Total Direct Investment (TDI)	5,518,600	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
Contingency	95,100	3% of TEC
Engineering	317,200	10% of TEC
Construction & Field Expense	634,300	20% of TEC
Contractor Fees	317,200	10% of TEC
Start-up Assistance	31,700	1% of TEC
Performance Test	31,700	1% of TEC
Total Indirect Investment (TII)	**1,427,200**	

Total Turnkey Cost (TTC)	**6,945,800**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor and scaled from similar projects.

[B] Capital equipment cost provided by vendor, scaled for capacity and ajdusted to 2019 dollars:
Capacity scaled using $C_n=r^{0.6}C$, Chemical Engineers' Handbook, Fifth Edition.

Alstom Sept. 2006
SDA System and Pulse Jet Fabric Filter Baghouse
$43,000,000 Total
2 SDA vessels (66' dia. X 52' side height)
Support Steel, roof penthouse
3 rotary atomizers per vessel
Lime prep system - lime silos, lakers, pumps, controls
Pulse jet fabric filter, including pulse systrem, support steel, roof penthouse
2 350-hp rotary screw air compressors, 3800 gal air receiver, air dryrers, filters
No erection or installation
No piping or insulation

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual,
Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

CRK No. 1 Dry FGD/Fabric Filter Annual Cost Summary

Description of Cost	($)[A]	Remarks
Direct Annual Costs [B]		
Dry FGD Labor	49,300	1 hr per shift, assumed 8 hr shifts
Dry FGD Supervisor	7,400	15% of labor
Fabric Filter Labor	65,700	2 hr per shift, assumed 8 hr shifts
Fabric Filter Supervisor	9,900	15% of labor
Solvent (Reagent)	256,400	Consumption x cost
Fabric Filter Bag Replacement	170,700	Labor plus bag cost
Solids Scrubber Disposal	56,200	Production x cost
Solids Fly Ash Disposal	94,100	Production x cost
Maintenance Labor, Dry FGD	49,300	1 hr per shift, assumed 8 hr shifts
Maintenance Material, Dry FGD	49,300	100% of labor
Maintenance Labor, Fabric F.	65,700	2 hr per shift, assumed 8 hr shifts
Maintenance Material, Fabric F.	65,700	100% of labor
Induced Draft Fan	129,400	Consumption x cost
Pump	42,900	Consumption x cost
Direct Annual Costs (DAC)	**1,112,000**	

Indirect Annual Costs [C]		
Overhead	473,600	60% of O&M Labor
Administrative Charges	307,800	2% of Total Capital Investment
Property Taxes	153,900	1% of Total Capital Investment
Insurance	153,900	1% of Total Capital Investment
Dry FGD Annualized Costs[D]	692,600	(Capital Investment) x (CFR of 0.08204)
Fabric Filter Annualized Costs[D]	569,800	(Capital Investment) x (CFR of 0.08204)
Indirect Annual Costs (IAC)	**2,351,600**	

Total Annualized Costs (TAC)	**3,463,600**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs are based on site-specific design parameters.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers and fabric filters.

[D] Capital Recovery Factor (CFR) based on 20 year life and an interst rate of 5%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

CRK No. 1 Dry Sorbent Injection Capital Cost Summary

Description of Cost	($)[A]	Remarks
Direct Capital Costs		
DSI Equipment[B]	840,062	Vendor Quote
Control/Instrumentation[C]	84,000	10% of Equipment Cost
Sales Tax	50,400	6% of Equipment Cost
Freight[C]	42,000	5% of Equipment Cost
Total Equipment Cost (TEC)	**1,016,500**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	864,000	Based on percentage of TEC: 12% Foundation & Supports, 40% Erection, 1% Electrical Installation, 30% Piping, 1% Painting, 1% Insulation
Flatwork/Drainage/Retrofit[D]	52,000	Estimated HDR
Total Direct Investment (TDI)	1,932,500	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
Contingency	101,700	10% of TEC (Retrofit Adjustment, HDR)
Engineering	50,800	5% of TEC
Construction & Field Expense	101,700	10% of TEC
Contractor Fees	101,700	10% of TEC
Start-up Assistance	10,200	1% of TEC
Performance Test	20,300	2% of TEC (Adjusted HDR)
Total Indirect Investment (TII)	**386,400**	

Total Turnkey Cost (TTC)	**2,318,900**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

CRK No. 1 Dry Sorbent Injection Annual Cost Summary

Description of Cost	($)[A]	Remarks
Direct Annual Costs [B]		
DSI Labor	24,600	1/2 hr per shift, assumed 8 hr shifts
DSI Supervisor	3,700	15% of labor
Solvent (Trona)	31,000	Consumption x cost
Solids Fly Ash Disposal	15,200	Production x cost
Maintenance Labor	24,600	1/2 hr per shift, assumed 8 hr shifts
Maintenance Material, Dry FGD	24,600	100% of labor
Induced Draft Fan/Pumps	13,000	Consumption x cost
Direct Annual Costs (DAC)	**136,700**	
Indirect Annual Costs [C]		
Overhead	65,100	60% of O&M Labor
Administrative Charges	46,400	2% of Total Capital Investment
Property Taxes	23,200	1% of Total Capital Investment
Insurance	23,200	1% of Total Capital Investment
DSI Annualized Costs[D]	190,200	(Capital Investment) x (CFR of 0.08204)
Indirect Annual Costs (IAC)	**348,100**	
Total Annualized Costs (TAC)	**484,800**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs are based on site-specific design parameters and vendor quote.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers and fabric filters.

[D] Capital Recovery Factor (CFR) based on 20 year life and an interst rate of 5%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

CRK No. 2 Dry FGD Capital Cost Summary

Description of Cost	**($)[A]**	**Remarks**
Direct Capital Costs		
Dry FGD Equipment[B]	3,369,794	Scaled Quote
Control/Instrumentation[C]	337,000	10% of Equipment Cost
Sales Tax	202,200	6% of Equipment Cost
Freight[C]	168,500	5% of Equipment Cost
Total Equipment Cost (TEC)	**4,077,500**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	3,465,900	Based on percentage of TEC: 12% Foundation & Supports, 40% Erection, 1% Electrical Installation, 30% Piping, 1% Painting, 1% Insulation
Retrofit Cost Adjustments [D]		
Infrastructure Relocation/Demolition	154,800	Estimated by HDR
Exhaust Stack	97,300	Estimated by HDR
Retrofit Cost Addition	204,200	Estimated by HDR
Total Direct Investment (TDI)	7,999,700	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
Contingency	122,300	3% of TEC
Engineering	407,800	10% of TEC
Construction & Field Expense	407,800	10% of TEC
Contractor Fees	407,800	10% of TEC
Start-up Assistance	40,800	1% of TEC
Performance Test	40,800	1% of TEC
Total Indirect Investment (TII)	**1,427,300**	

Total Turnkey Cost (TTC)	**9,427,000**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor, scaled for capacity and ajdusted to 2019 dollars:
Capacity scaled using $C_n = r^{0.6}C$, Chemical Engineers' Handbook, Fifth Edition.

Alstom Sept. 2006
SDA System and Pulse Jet Fabric Filter Baghouse
$43,000,000 Total
2 SDA vessels (66' dia. X 52' side height)
Support Steel, roof penthouse
3 rotary atomizers per vessel
Lime prep system - lime silos, lakers, pumps, controls
Pulse jet fabric filter, including pulse systrem, support steel, roof penthouse
2 350-hp rotary screw air compressors, 3800 gal air receiver, air dryrers, filters
No erection or installation
No piping or insulation

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

CRK No. 2 Dry FGD Fabric Filter Capital Cost Summary

Description of Cost	**($)**[A]	**Remarks**
Direct Capital Costs		
Fabric Filter Equipment[B]	2,930,256	Scaled Quote
Control/Instrumentation[C]	293,000	10% of Equipment Cost
Sales Tax	175,800	6% of Equipment Cost
Freight[C]	146,500	5% of Equipment Cost
Total Equipment Cost (TEC)	**3,545,600**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	2,623,700	Based on percentage of TEC: 4% Foundation & Supports, 50% Erection, 8% Electrical Installation, 1% Piping, 4% Painting, 7% Insulation
Retrofit Cost Adjustments [D]		
Infrastructure Relocation/Demolition	-	Included in SDA Costs
Exhaust Stack	-	Included in SDA Costs
Retrofit Cost Addition	-	Included in SDA Costs
Total Direct Investment (TDI)	6,169,300	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
Contingency	106,400	3% of TEC
Engineering	354,600	10% of TEC
Construction & Field Expense	709,100	20% of TEC
Contractor Fees	354,600	10% of TEC
Start-up Assistance	35,500	1% of TEC
Performance Test	35,500	1% of TEC
Total Indirect Investment (TII)	**1,595,700**	

Total Turnkey Cost (TTC)	**7,765,000**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor, scaled for capacity and ajdusted to 2019 dollars:
Capacity scaled using $C_n=r^{0.6}C$, Chemical Engineers' Handbook, Fifth Edition.

Alstom Sept. 2006
SDA System and Pulse Jet Fabric Filter Baghouse
$43,000,000 Total
2 SDA vessels (66' dia. X 52' side height)
Support Steel, roof penthouse
3 rotary atomizers per vessel
Lime prep system - lime silos, lakers, pumps, controls
Pulse jet fabric filter, including pulse systrem, support steel, roof penthouse
2 350-hp rotary screw air compressors, 3800 gal air receiver, air dryrers, filters
No erection or installation
No piping or insulation

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

CRK No. 2 Dry FGD/Fabric Filter Annual Cost Summary

Description of Cost	**($)**[A]	**Remarks**
Direct Annual Costs [B]		
Dry FGD Labor	49,300	1 hr per shift, assumed 8 hr shifts
Dry FGD Supervisor	7,400	15% of labor
Fabric Filter Labor	65,700	2 hr per shift, assumed 8 hr shifts
Fabric Filter Supervisor	9,900	15% of labor
Solvent (Reagent)	288,500	Consumption x cost
Fabric Filter Bag Replacement	192,100	Labor plus bag cost
Solids Scrubber Disposal	63,200	Production x cost
Solids Fly Ash Disposal	105,800	Production x cost
Maintenance Labor, Dry FGD	49,300	1 hr per shift, assumed 8 hr shifts
Maintenance Material, Dry FGD	49,300	100% of labor
Maintenance Labor, Fabric F.	65,700	2 hr per shift, assumed 8 hr shifts
Maintenance Material, Fabric F.	65,700	100% of labor
Induced Draft Fan	145,600	Consumption x cost
Pump	48,300	Consumption x cost
Direct Annual Costs (DAC)	**1,205,800**	
Indirect Annual Costs [C]		
Overhead	505,700	60% of O&M Labor
Administrative Charges	343,800	2% of Total Capital Investment
Property Taxes	171,900	1% of Total Capital Investment
Insurance	171,900	1% of Total Capital Investment
Dry FGD Annualized Costs[D]	773,400	(Capital Investment) x (CFR of 0.08204)
Fabric Filter Annualized Costs[D]	637,000	(Capital Investment) x (CFR of 0.08204)
Indirect Annual Costs (IAC)	**2,603,700**	
Total Annualized Costs (TAC)	**3,809,500**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs are based on site-specific design parameters.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers and fabric filters.

[D] Capital Recovery Factor (CFR) based on 20 year life and an interst rate of 5%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

CRK No. 2 Dry Sorbent Injection Capital Cost Summary

Description of Cost	($)[A]	Remarks
Direct Capital Costs		
DSI Equipment[B]	939,296	Vendor Quote
Control/Instrumentation[C]	93,900	10% of Equipment Cost
Sales Tax	56,400	6% of Equipment Cost
Freight[C]	47,000	5% of Equipment Cost
Total Equipment Cost (TEC)	**1,136,600**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	966,100	Based on percentage of TEC: 12% Foundation & Supports, 40% Erection, 1% Electrical Installation, 30% Piping, 1% Painting, 1% Insulation
Flatwork/Drainage/Retrofit[D]	52,000	Estimated HDR
Total Direct Investment (TDI)	2,154,700	**TEC + TIC + Site Prep. = TDI**
Indirect Capital Cost [C]		
Contingency	113,700	10% of TEC (Retrofit Adjustment, HDR)
Engineering	56,800	5% of TEC
Construction & Field Expense	113,700	10% of TEC
Contractor Fees	113,700	10% of TEC
Start-up Assistance	11,400	1% of TEC
Performance Test	22,700	2% of TEC (Adjusted HDR)
Total Indirect Investment (TII)	**432,000**	
Total Turnkey Cost (TTC)	**2,586,700**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

CRK No. 2 Dry Sorbent Injection Annual Cost Summary

Description of Cost	**($)[A]**	**Remarks**
Direct Annual Costs [B]		
DSI Labor	24,600	1/2 hr per shift, assumed 8 hr shifts
DSI Supervisor	3,700	15% of labor
Solvent (Trona)	34,700	Consumption x cost
Solids Fly Ash Disposal	17,000	Production x cost
Maintenance Labor	24,600	1/2 hr per shift, assumed 8 hr shifts
Maintenance Material, Dry FGD	24,600	100% of labor
Induced Draft Fan/Pumps	14,500	Consumption x cost
Direct Annual Costs (DAC)	**143,700**	
Indirect Annual Costs [C]		
Overhead	67,300	60% of O&M Labor
Administrative Charges	51,700	2% of Total Capital Investment
Property Taxes	25,900	1% of Total Capital Investment
Insurance	25,900	1% of Total Capital Investment
DSI Annualized Costs[D]	212,200	(Capital Investment) x (CFR of 0.08204)
Indirect Annual Costs (IAC)	**383,000**	
Total Annualized Costs (TAC)	**526,700**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs are based on site-specific design parameters and vendor quote.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers and fabric filters.

[D] Capital Recovery Factor (CFR) based on 20 year life and an interst rate of 5%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

Cost Estimate

Total Capital Investment (TCI)

Capital costs for the SCR (SCR_{cost}) =	$6,224,628	in 2019 dollars
Reagent Preparation Cost (RPC) =	$2,317,828	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2019 dollars
Balance of Plant Costs (BPC) =	$2,809,173	in 2019 dollars
Total Capital Investment (TCI) =	$14,757,119	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$6,224,628 in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529{,}000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	

Direct Annual Costs (DAC) =	$141,853	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,186,314	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,328,167	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	
Annual Catalyst Replacement Cost =		

For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.

Method 1 (for all fuel types):	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	* Calculation Method 1 selected.
Method 2 (for coal-fired industrial boilers):	$(Q_B/NPHR) \times 0.4 \times (CoalF)^{2.9} \times (NRF)^{0.71} \times (CC_{replace}) \times 35.3$	
Direct Annual Cost =		

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,793 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,183,521 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,186,314 in 2019 dollars

Total Annual Cost (TAC) =	$1,328,167	per year in 2019 dollars
NOx Removed =	91	tons/year
Cost Effectiveness =	$14,657	per ton of NOx removed in 2019 dollars

Cost Estimate

Total Capital Investment (TCI)

Capital costs for the SCR (SCR_{cost}) =	$7,431,706	in 2019 dollars
Reagent Preparation Cost (RPC) =	$2,428,131	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2019 dollars
Balance of Plant Costs (BPC) =	$3,037,380	in 2019 dollars
Total Capital Investment (TCI) =	$16,766,382	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$7,431,706 in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529{,}000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	

Direct Annual Costs (DAC) =	$156,864	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,347,578	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,504,442	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	
Annual Catalyst Replacement Cost =		

For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.

Method 1 (for all fuel types):	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	* Calculation Method 1 selected.
Method 2 (for coal-fired industrial boilers):	$(Q_B/NPHR) \times 0.4 \times (CoalF)^{2.9} \times (NRF)^{0.71} \times (CC_{replace}) \times 35.3$	
Direct Annual Cost =		

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,914 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,344,664 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,347,578 in 2019 dollars

Total Annual Cost (TAC) =	$1,504,442	per year in 2019 dollars
NOx Removed =	109	tons/year
Cost Effectiveness =	$13,785	per ton of NOx removed in 2019 dollars

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$1,201,809	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,748,046	in 2019 dollars
Total Capital Investment (TCI) =	$3,834,812	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$1,201,809	in 2019 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$1,748,046	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$68,102	in 2019 dollars
Indirect Annual Costs (IDAC) =	$309,278	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$377,379	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$57,522	in 2019 dollars
Annual Reagent Cost =	$q_{sol} \times Cost_{reag} \times t_{op}$ =	$8,760	in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$557	in 2019 dollars
Annual Water Cost =	$q_{water} \times Cost_{water} \times t_{op}$ =	$212	in 2019 dollars
Additional Fuel Cost =	$\Delta Fuel \times Cost_{fuel} \times t_{op}$ =	$994	in 2019 dollars
Additional Ash Cost =	$\Delta Ash \times Cost_{ash} \times t_{op} \times (1/2000)$ =	$56	in 2019 dollars
Direct Annual Cost =		$68,102	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$1,726	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$307,552	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$309,278	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$377,379	per year in 2019 dollars
NOx Removed =	25	tons/year
Cost Effectiveness =	$14,914	per ton of NOx removed in 2019 dollars

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$1,299,439 in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,900,625 in 2019 dollars
Total Capital Investment (TCI) =	$4,160,084 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220,000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147,000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220,000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147,000 \times ((Q_B/NPHR)\times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$1,299,439 in 2019 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69,000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69,000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320,000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213,000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320,000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213,000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$1,900,625 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$74,757 in 2019 dollars
Indirect Annual Costs (IDAC) =	$335,511 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$410,268 in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$62,401 in 2019 dollars
Annual Reagent Cost =	$q_{sol} \times Cost_{reag} \times t_{op}$ =	$10,231 in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$651 in 2019 dollars
Annual Water Cost =	$q_{water} \times Cost_{water} \times t_{op}$ =	$248 in 2019 dollars
Additional Fuel Cost =	$\Delta Fuel \times Cost_{fuel} \times t_{op}$ =	$1,160 in 2019 dollars
Additional Ash Cost =	$\Delta Ash \times Cost_{ash} \times t_{op} \times (1/2000)$ =	$66 in 2019 dollars
Direct Annual Cost =		$74,757 in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$1,872 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$333,639 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$335,511 in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$410,268 per year in 2019 dollars
NOx Removed =	30 tons/year
Cost Effectiveness =	$13,462 per ton of NOx removed in 2019 dollars

Project: Industrial Boiler DSI
Date: 8 19 2019
Estimate Basis: Conceptual
Costs: 2019$
Location: American Crystal Sugar

CONCEPTUAL CAPITAL COST ESTIMATE SUMMARY

I.	MOBILIZATION AND SITE PREPARATION	$40,000
II.	SITE IMPROVEMENTS	$41,000
III.	DRY SORBENT INJECTION EQUIPMENT	$1,865,000
IV.	ELECTRICAL MODS	$373,000
	SUBTOTAL CONSTRUCTION	$2,320,000
	DESIGN/ENGINEERING	$140,000
	PERFORMANCE TESTING	$100,000
	START-UP AND COMMISSIONING	$96,000
	CONTINGENCY (20%)	$460,000
	TOTAL CAPITAL COST	$3,120,000

I. MOBILIZATION AND SITE PREPARATION

Item	Quantity	Units	Unit Price	Item Cost	Total
Geotechnical Services	1	LS	$10,000	$10,000	
Surveying	1	LS	$5,000	$5,000	
Construction Offices	1	LS	$10,000	$10,000	
Mobilization	1	LS	$10,000	$10,000	
Temporary Power	1	LS	$5,000	$5,000	
Const. Access, Parking and Laydowr	1	LS	$0	$0	
Temporary Fencing	0	lf	$15	$0	
Subtotal I					$40,000

II. SITE IMPROVEMENTS

Item	Quantity	Units	Unit Price	Item Cost	Total
Earthwork					
General Earthwork	89	cy	$7	$1,000	
Finishing Grading	89	sy	$1.00	$0	
Roadways	0	sy	$60	$0	
Asphalt Pavement	0	sy	$60	$0	
Fire Protection	1	LS	$10,000	$10,000	
Water Supply	1	LS	$5,000	$5,000	
Drains and Sumps	1	LS	$20,000	$20,000	
Storm Water System	1	LS	$5,000	$5,000	
Yard Lighting	1	LS	$0	$0	
Subtotal II					$41,000

Notes:

IV. DRY SORBENT INJECTION EQUIPMENT

Item	Quantity	Units	Unit Price	Item Cost	Total
Foundations	1	LS	$25,000	$25,000	
DSI Equipment	1	LS	$865,000	$865,000	
Erection	1	LS	$300,000	$300,000	
Viper Mills	1	LS	$475,000	$475,000	
Dehimidifiers and Condensers	1	LS	$150,000	$150,000	
Piping	1	LS	$50,000	$50,000	
Subtotal IV					$1,865,000

IV. ELECTRICAL MODS

Item	Quantity	Units	Unit Price	Item Cost	Total
Allowance	1	LS	$373,000	$373,000	
Subtotal V					$373,000

Subtotal I through V	$2,320,000

SYSTEM OPERATING COST, $ US 2019

I.	LABOR	22,000
II.	REAGENTS AND SUPPLIES	55,000
III.	EQUIPMENT MAINTENANCE	23,000
IV.	ASH DISPOSAL COST	27,000
	SUBTOTAL OPERATION & MAINTENANCE	127,000
	CONTINGENCY (20%)	25,000
	TOTAL ANNUAL OPERATION & MAINTENANCE COST	152,000
	TOTAL ANNUAL LOST REVENUE	23,000
	Capacity Factor	85.1%

	Item	Qnty	Units	Unit Price	Item Cost
I.	LABOR				
	Operators	0.20			
	Required Staff	416	hr	54.00	22,000
	Maintenance	0			
	Required Staff	0	hr	70.00	0
	Subtotal				22,000
	Notes:				
II.	REAGENTS AND SUPPLIES				
	Trona	250	Tons	220	55,000
	Subtotal				55,000
III.	EQUIPMENT MAINTENANCE				
	(1% of construction subtotal cost)	1		23,200	23,200
	Subtotal				23,000
IV.	ASH DISPOSAL COST				
	Additional ash requiring disposal (1.43 lbs per lb Trona @ NSR 0.14)	1,333	Tons	20	27,000
	Subtotal				27,000
	Subtotal Costs I through IV				127,000
V.	UTILITIES				
	Electricity	186,369	kWh	0.06	11,000
	Electrical Capacity	25	kW	460	12,000
	Subtotal				23,000

SPRING CREEK MINE
QUALITY SPECIFICATIONS

QUALITY PARAMETER	TYPICAL (MEAN VALUE)	STANDARD DEVIATION	TYPICAL 95% RANGE		TYPICAL DRY VALUE	TYPICAL MOISTURE-ASH FREE VALUE
			-2 STD DEV	+2 STD DEV		
PROXIMATE						
% Moisture	25.40	0.56	24.28	26.52		
% Ash	4.12	0.33	3.46	4.78	5.52	
% Volatile	31.26	0.81	29.64	32.88	41.90	44.35
% Fixed Carbon	39.23	0.80	37.63	40.83	52.59	55.66
BTU/lb	9350	103	9132	9544	12517	13249
MAFBTU	13249	80.08	13089	13409		
Dry BTU	12517	93.71	12330	12705		
% Sulfur	0.38	0.07	0.20	0.48	0.46	0.48
ULTIMATE						
% Moisture	25.40	0.56	24.28	26.52		
% Carbon	54.14	3.28	47.58	60.70	72.57	76.82
% Hydrogen	3.80	0.23	3.34	4.26	5.09	5.39
% Nitrogen	0.71	0.09	0.53	0.89	0.95	1.01
% Chlorine	0.00	0.01	0.00	0.01	0.00	0.00
% Sulfur	0.34	0.07	0.20	0.48	0.46	0.48
% Ash	4.12	0.33	3.46	4.78		
% Oxygen	11.50	0.70	10.10	12.90	15.42	16.32
SULFUR FORMS						
Pyritic Sulfur (%)	0.05	0.03	0.00	0.11	0.07	0.07
Sulfate Sulfur (%)	0.01	0.015	0.00	0.04	0.01	0.01
Organic Sulfur (%)	0.28	0.06	0.16	0.40	0.38	0.40
Total Sulfur (%)	0.34	0.07	0.20	0.48	0.46	0.48
MINERAL ANALYSIS OF ASH						
% Silicon Dioxide (Silica, SiO_2)	32.52	2.78	26.96	38.08		
% Aluminum Oxide (Alumina, Al_2O_3)	17.69	1.09	15.51	19.87		
% Titanium Dioxide (Titania, TiO_2)	1.13	0.10	0.93	1.33		
% Iron Oxide (Ferric Oxide, Fe_2O_3)	4.76	0.47	3.82	5.70		
% Calcium Oxide (Lime, CaO)	15.36	1.41	12.54	18.18		
% Magnesium Oxide (Magnesia, MgO)	3.69	0.85	1.99	5.39		
% Potassium Oxide (K_2O)	0.63	0.14	0.35	0.91		
% Sodium Oxide (Na_2O)	8.24	1.00	6.24	10.24		
% Sulfur Trioxide (SO_3)	14.07	2.50	9.07	19.07		
% Phosphorous Pentoxide (P_2O_5)	0.35	0.06	0.23	0.47		
% Strontium Oxide (SrO)	0.37	0.22	0.00	0.81		
% Barium Oxide (BaO)	1.19	0.31	0.57	1.81		
% Undetermined	0.00	1.00	0.00	2.00		
Base/Acid Ratio	0.64	0.08	0.48	0.80		
Base Value	32.68	2.20	28.28	37.08		
Acid Value	51.34	3.00	45.34	57.34		
ASH FUSION TEMPERATURES						
Reducing (^{O}F)						
Initial	2106	37	2031	2181		
Softening (H=W)	2129	36	2056	2202		
Hemispherical (H=1/2W)	2141	39	2062	2220		
Fluid	2164	51	2062	2266		
Fluid-Initial Temp. Difference	58	40	0	138		
Oxidizing (^{O}F)						
Initial	2351	98	2156	2546		
Softening (H=W)	2366	81	2204	2528		
Hemispherical (H=1/2W)	2391	73	2245	2537		
Fluid	2423	77	2268	2578		
Fluid-Initial Temp. Difference	72	60	0	192		

SPRING CREEK MINE
QUALITY SPECIFICATIONS (Continued)

QUALITY PARAMETER	TYPICAL (MEAN VALUE)	STANDARD DEVIATION	TYPICAL 95% RANGE -2 STD DEV	+2 STD DEV
ADDITIONAL ANALYSES AND CALCULATED VALUES				
T250 Temperature (^{O}F)	2153	91.88	1969	2337
HGI (at as-received moisture)	60.6	5.6	49	72
HGI % Moisture	24.13	3.88	16	32
Critical Viscosity Temperature (^{O}F)	0	0	0	0
Critical Viscosity (Poises)	0	0	0	0
% Equilibrium Moisture	23.93	0.56	22.81	25.05
Specific Gravity	1.10	0.015	1.07	1.13
%Alkalies NA2O Dry (Total Alkali Content on Coal)	0.478	0.070	0.34	0.62
%Water Soluble Alk - Na2O	0.000	0.000	0.00	0.00
%Water Soluble Alk - K2O	0.000	0.000	0.00	0.00
%Na2O - Dry Coal	0.46	0.03	0.40	0.52
%Na2O As-received Coal	0.34	0.02	0.30	0.38
Silica Value (Silica Ratio)	57.73			
Slag Factor	0.28	0.14	0.00	0.56
Slag factor per Fusion Temperature	2163	85	1993	2333
Dolomite Ratio	58.29	3.25	51.79	64.79
Ash Precipitation Index	3.97	10.1	0.00	24.17
Silica to Alumina Ratio	1.84	0.14	1.56	2.12
Calcium to Silica Ratio	0.47	0.34	0.00	1.15
Iron to Calcium Ratio	0.31	0.07	0.17	0.45
Fouling Factor (Fouling Index)	5.25	1.41	2.43	8.07
SO2/MMBTU	0.80	0.075	0.58	0.88
lbs S/MMBTU	0.36	0.075	0.21	0.51
lbs Sodium/MMBTU	0.364	0.023	0.32	0.41
lbs Ash/MMBTU	4.41	0.5	3.41	5.41

TYPICAL COAL SIZE 2 inch

Size Fraction	Wt. Percent	Cumulative Wt. Percent	Wt. Percent Passing Top
+3" RD.	0%	0%	100%
3" RD. x 2" RD.	4%	4%	100%
2" RD. x 1" RD.	20%	24%	96%
1" RD. x 1/2" RD.	28%	52%	76%
1/2" RD. x 4 M	20%	71%	48%
4 M x 60 M	13%	84%	29%
60 M x 0	16%	100%	16%

TRACE ELEMENT SUMMARY

Parts Per Million Whole Coal, Dry Basis	TYPICAL (MEAN VALUE)	STANDARD DEVIATION	TYPICAL 95% RANGE -2 STD DEV	+2 STD DEV
ANTIMONY (Sb)	n/a	n/a	n/a	n/a
ARSENIC (As)	1.50	1.00	0.00	3.50
BARIUM (Ba)	n/a	n/a	n/a	n/a
BERYLLIUM (Be)	0.21	0.08	0.06	0.36
BORON (B)	n/a	n/a	n/a	n/a
BROMIDE (Br)	n/a	n/a	n/a	n/a
CADMIUM (Cd)	0.18	0.02	0.14	0.22
CHLORINE (Cl)	9.15	3.75	1.65	16.65
CHROMIUM (Cr)	2.40	0.75	0.90	3.90
COBALT (Co)	n/a	n/a	n/a	n/a
COPPER (Cu)	n/a	n/a	n/a	n/a
FLUORINE (F)	41.90	11.00	19.90	63.90
LITHIUM (Li)	n/a	n/a	n/a	n/a
MANGANESE Mn)	16.20	7.90	0.40	32.00
MERCURY (Hg)	0.07	0.03	0.01	0.13
MOLYBDNEUM (Mo)	n/a	n/a	n/a	n/a
NICKEL (Ni)	1.53	1.00	0.00	3.53
LEAD (Pb)	2.60	1.00	0.60	4.60
SELENUIM (Se)	1.20	0.90	0.00	3.00
SILVER (Ag)	n/a	n/a	n/a	n/a
STRONTIUM (Sr)	n/a	n/a	n/a	n/a
THALLIUM (Tl)	n/a	n/a	n/a	n/a
THORIUM (Th)	n/a	n/a	n/a	n/a
TIN (Sn)	n/a	n/a	n/a	n/a
URANIUM (U)	n/a	n/a	n/a	n/a
VANADIUM (V)	n/a	n/a	n/a	n/a
ZIRCONIUM (Zr)	n/a	n/a	n/a	n/a
ZINC (Zn)	n/a	n/a	n/a	n/a

*** All negative numbers were converted to 0.00**

Regional Haze Four Factor Analysis

American Crystal Sugar Company

East Grand Forks, MN

For Submittal to:
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155-4194

August 28, 2020

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Appendix A. Cost Calculations

1 Introduction

In response to the Minnesota Pollution Control Agency (MPCA) Request for Information (ROI) dated February 14, 2020, American Crystal Sugar Company (ACSC) is providing the following Four Factor Analysis to address pollutants of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emitted from the coal-fired boilers at the East Grand Forks (EGF) facility.

This analysis is being provided for planning purposes and is based on budgetary cost information obtained from scaled vendor quotes for similar systems as well as methodology presented in the U.S. Environmental Protection Agency's (EPA) Air Pollution Control Cost Manual. This approach is intended to provide a study-level estimate (+/-30%) of capital and annual costs. In the event that emission reductions will be proposed for inclusion in the State Implementation Plan (SIP), it is requested that ACSC be given the opportunity to further refine the cost data to incorporate site-specific quotes reflecting current market conditions and unique site physical constraints.

1.1 Analysis Methodology

Following the EPA's *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 20, 2019, the Four Factor Analysis addresses:

- The costs of compliance;
- The time necessary for compliance;
- The energy and non-air quality environmental impacts of compliance; and,
- The remaining useful life of the source(s).

The first step in the process is identification of all available retrofit technologies for each pollutant (SO_2 and NO_x). Control options that are technically infeasible are eliminated and remaining options are evaluated to determine their control effectiveness and economic, energy and environmental impacts.

Technically feasible control technologies are ranked in the order of highest expected emission reduction to lowest expected emission reduction and are evaluated following a "top-down" approach similar to Best Available Control Technology (BACT) analyses.

Impacts considered for each control technology include: cost of compliance, energy impacts, non-air quality environmental impacts and the remaining useful life of the unit to be controlled.

1.2 EGF Source Parameters

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 electrostatic precipitators to control particulate matter 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 (PRB).

The boilers are identified as EU001 and EU002 in Air Emission Permit No. 11900002-006. The operating permit limits each boiler to maximum SO_2 emissions of 391.8 lb/hr (1.10 lb/MMBtu) and NO_x emissions of 227.9 lb/hr (0.64 lb/MMBtu).

As indicated in the EPA's *Guidance on Regional Haze State Implementation Plans*, a state may use a source's annual emissions in tons to determine actual visibility impacts. Therefore, actual emission levels based on source test data were used to characterize emissions-related factors in this analysis. The average SO_2 emission rate from the EGF boilers as reported in the most recent emission inventory is 0.45 lb/MMBtu and 452 tons per year (tpy) for each boiler. The average NO_x emission rate from the EGF boilers as reported in the most recent emission inventory is 0.34 lb/MMBtu and 340 tpy for each boiler.

Because the boilers are of identical size and type, control technology costs and design features would be the same for both boilers. It is anticipated that the Four Factor Analysis applies to the EGF facility as a whole, and potential control technology determinations would not be made for a single boiler, but instead would apply to both boilers at the facility. Therefore, the average emission rate for the two boilers was used in the analysis to determine costs of compliance.

2 Four Factor Analysis

2.1 Applicable Pollutants

The Four Factor Analysis addresses criteria pollutants of SO_2 and NO_x.

SO_2 Formation. SO_2 emissions are formed from the oxidation of organic sulfur and pyritic sulfur in the coal during the combustion process. The majority of sulfur is oxidized to SO_2, however, a small quantity may be further oxidized to form sulfur trioxide (SO_3). Approximately 90% of the sulfur present in the subbituminous coal will be emitted as sulfur oxides (SO_x) compounds. Alkaline ash from some coals (including PRB coals) may cause some of the sulfur to react in the furnace to form various sulfate salts that are then retained in the fly ash. Sulfuric acid mist (H_2SO_4) forms when SO_2 emissions react with moisture and oxygen in the environment.

NO_x Formation. There are two primary mechanisms of NO_x formation in coal-fired industrial boilers: thermal production of NOx from atmospheric nitrogen and oxygen, and oxidation of nitrogen bound in the fuel. High combustion temperatures cause the nitrogen (N_2) and oxygen (O_2) molecules in the combustion air to react and form thermal NO_x. Because thermal NO_x is primarily a function of combustion temperature, NO_x emission rates vary with burner and source design. Experimental measurements of thermal NO_x formation have shown that the NO_x concentration is exponentially dependent on temperature and is proportional to the N_2 concentration in the flame, the square root of the O_2 concentration in the flame, and the gas residence time[1]. The formation of fuel NO_x from reactions of fuel bound nitrogen and air can

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[1] AP42, Chapter 1, Bituminous and Subbituminous Coal Combustion, (9/98).

account for up to 80% of total NO_x from coal combustion. Subbituminous coals contain from 0.5 to 2 percent by weight fuel-bound nitrogen.

2.2 Economic Evaluation Criteria

Costs of compliance are directly related to the technically feasible control technology option selected and the level of emission reduction experienced from the control. Costs are expressed in terms of dollars per ton of pollutant removed, where the cost is the annualized capital and operating costs, and the tons of pollutant removed is the incremental reduction in pollutant emissions over current baseline (actual) emission levels.

Base economic criteria used in this analysis are listed in Table 1.

Table 1 – Economic Evaluation Criteria.

Economic Parameter	Value
Interest Rate, percent	7[A]
Control Equipment Economic Life, years	15 & 20[B]
Base Labor Cost, $/hr	60[C]
Energy Cost, $/kW-hr	0.06[D]

[A] EPA Air Pollution Control Cost Manual, Seventh Edition, January 2017, Chapter 2, Section 2.4.2.

[B] Based on Control Equipment Type. EPA Memorandum, Calculating Amortized Capital Costs, July 24, 1987, Robert D. Bauman, Chief, Standards and Implementation Branch.

[C] Loaded labor rate obtained from ACSC.

[D] Actual ACSC electricity cost.

Cost estimates used in the analysis have been compiled from a number of data sources. In general, the cost estimates were performed following guidance provided in EPA's *Air Pollution Control Cost Manual, Seventh Edition*, January 2017. The EPA control cost manual data was supplemented with vendor supplied quotations when available and general engineering estimates. Detailed cost estimate and support data have been provided in Appendix A.

2.3 SO_2 Analysis

Because the two coal-fired boilers at the EGF facility are identical, the analysis was prepared for one individual boiler. The results of the analysis can be applied equally to each boiler.

2.3.1 Identification of SO_2 Control Technologies

Control of SO_2 emissions from fuel-combustion sources can be accomplished through two approaches: removal of elemental sulfur from the fuel prior to combustion, and flue gas desulfurization (FGD), which consists of removal of SO_2 from flue gas after combustion (post-combustion control).

Many oil refineries operate catalyst-based desulfurization units to remove organic sulfur from liquid crude oil. However, in solid fuels, such as coal, a significant fraction of the sulfur is in the form of pyrite (FeS_2) or other mineral sulfates. It is possible to remove some mineral sulfates through physical processes such as washing and/or chemical processing. However, desulfurization of solid fuels is generally viewed as inefficient and expensive. Additionally, organic sulfur cannot be removed by physical cleaning. It is unlikely that sufficient desulfurization of solid fuels can be accomplished to meet anticipated emission requirements. Therefore removal of sulfur from the coal prior to combustion will not be considered a viable option for this analysis.

FGD technologies can be divided into two main categories: regenerative and throwaway processes. Regenerative processes recover sulfur in a usable form that can be sold as a reusable sulfur product. Throwaway processes remove sulfur from flue gas and scrubber byproducts are subsequently discarded. All of the FGD technologies considered can achieve SO_2 removal efficiencies of 90 to 95% depending on the amount of sulfur in the coal. For relatively high sulfur coals, removal efficiencies can exceed 95%, while for lower sulfur coals (such as PRB), the achievable removal efficiency is typically less than 95%.

Regenerative processes, by nature, contain a regeneration step in the FGD process that results in higher costs than throwaway processes due to equipment and operation expenses. However, in instances where disposal options are limited and markets for recovered sulfur products are readily available, regenerative processes may be used. Potential regenerative processes that are available include the Wellman-Lord (W-L) process, magnesium oxide process, citrate scrubbing process, Flakt-Boliden process, aqueous carbonate process, Sulf-X process, Conosox process, Westvaco process and adsorption of SO_2 by a bed of copper oxide.

Throwaway processes such as limestone scrubbing have become widely accepted by the coal-fired power industry for FGD because limestone scrubbers have overall lower costs and are simpler to operate than regenerative processes. Because the throwaway process can achieve the same removal efficiencies as regenerative processes and cost less, this analysis for SO_2 will focus on throwaway processes and further discussion of regenerative processes will not be considered.

Throwaway processes can be divided into two categories, wet and dry. Wet or dry refers to the state of the waste by-products. Both wet and dry technologies have advantages and disadvantages with respect to initial capital and operational expenses.

2.3.1.1 Wet FGD Systems

Wet scrubbing (wet FGD) systems used for SO_2 reduction typically consist of the following operations: scrubbing or absorption, lime handling and slurry preparation, sludge processing, and flue gas handling.

Wet FGD technology is a well-established process for removing SO_2 from flue gas. In wet scrubbers, the flue gas enters a spray tower or absorber where it is sprayed with a water slurry, which is approximately 10 percent lime or limestone. Sodium alkali solutions can also be used in FGD systems, however these processes are considerably more expensive than lime. The preferred sorbents are limestone and lime, respectively, due to the availability and relatively low cost of limestone. Calcium in the slurry reacts with the SO_2 in the flue gas to form calcium sulfite or calcium sulfate. The overall chemical reaction can be simply expressed as:

$$SO_2 + CaCO_3 \rightarrow CaSO_3 + CO_2$$

Spent slurry from the reaction tank is pumped into a thickener where solids settle before being filtered for final dewatering to approximately 50 percent solids. Water removed during this process is sent to a process water holding tank, which eventually will require wastewater treatment. In a non-regenerative system, the waste sludge must also be disposed of properly. Finally, scrubbed flue gases are directed through a stack gas reheater in order to minimize corrosion downstream of the scrubber due to conversion of SO_2 to SO_3 and subsequently sulfuric acid (H_2SO_4). Reheating is sometimes needed for proper drafting and rise of exhaust gases out the stack, as well as minimizing condensation. As an alternative, the stack can be constructed of acid resistant material.

Most wet FGD systems have two stages: one for fly ash removal and one for SO_2 removal. The flue gas normally passes first through a fly ash removal device, either an electrostatic precipitator (ESP) or a bag filter, and then into the SO_2 absorber. There are many different types of absorbers that can be used in wet FGD systems, including: spray towers, venturis, plate towers, and mobile packed beds. However, many of these systems can result in scale buildup, plugging or erosion, which can affect the dependability and efficiency of the absorber. Therefore, simple scrubbers such as spray towers are commonly used. The chief drawback of the spray tower design is that it requires a higher liquid-to-gas ratio for equivalent removal of SO_2 than other absorber designs.

2.3.1.2 Dry FGD Systems

In contrast to wet scrubbing systems, dry FGD (spray dryer) systems use much smaller amounts of liquid. With a spray dryer system, the flue gases enter an absorbing tower (dryer) where the hot gases are contacted with a finely atomized slurry, which is usually a calcium-based sorbent such as calcium hydroxide or calcium oxide (lime). Acid gases and SO_2 are absorbed by the slurry mixture and react to form solid salts. The heat of the flue gas evaporates the water droplets in the sprayed slurry, and a non-saturated flue gas exits the absorber tower. The absorption process is also somewhat temperature dependent. Cooler flue gases allow the acid gases to more effectively react with the sorbents. The overall chemical reactions can be simply expressed as:

$$Ca(OH)_2 + SO_2 \rightarrow CaSO_3(s) + H_2O$$

$$Ca(OH)_2 + 2HCl \rightarrow CaCl_2\ (s) + 2H_2O$$

As can be seen above, one mole of calcium hydroxide will neutralize one mole of SO_2, whereas one mole of calcium hydroxide will neutralize two moles of hydrochloric acid (HCl). A similar reaction occurs with the neutralization of hydrofluoric acid (HF). These reactions demonstrate that when using a spray dryer the HCl and HF are removed more readily than SO_2. Reagent requirements should consider that the HCl and HF are removed first, followed by the reagent quantity required to remove the SO_2[2].

The heat of the flue gas evaporates the water droplets in the sprayed slurry, and a non-saturated flue gas exists the absorber tower. The exhaust stream exiting the absorber contains fly ash, calcium salts, and un-reacted lime, which must be sent to a particulate control device such as a fabric filter (baghouse). The particulate control device not only is necessary to control particulate matter, but also aids in acid-gas removal. Acid gases are removed when the flue gas comes in contact with the lime-containing particles on the surface of the ESP or baghouse. Fabric filters are considered to have slightly higher residual acid gas removal levels than ESPs because the acid gases must pass through the lime-containing filter cake in a fabric filter system. Modern dry FGD systems include a loop to recycle a portion of the baghouse-collected material for re-use in the FGD module because this material contains a relatively high amount of unreacted lime.

A lower efficiency Dry FGD process that utilizes either wet or dry reagent injected directly into the furnace or flue gas duct is known as dry sorbent injection (DSI). In general, hydrated lime, lime slurry or powdered lime is injected into the existing furnace or ductwork. The constraints of the existing furnace and ductwork configuration may limit expected retrofit control efficiencies of SO_2, which range from 25 to 50%. A significant drawback of this type of system is the increased maintenance costs incurred from directly injecting a sorbent into the furnace and associated duct work and the potential to significantly reduce the useful life of the boiler. Although DSI is a type of Dry FGD process, it will be referred to separately in this analysis.

2.3.2 SO_2 Control Technology Effectiveness

Effectiveness is measured by the amount of SO_2 removed from each control technology based on a comparison of the controlled emission rates to the baseline emission rates of the boilers. Table 2 provides a summary of the SO_2 control technology effectiveness.

Table 2 – SO_2 Control Technology Effectiveness.

Control Technology	Percent SO_2 Reduction[A]	Emission Rate (lb/MMBtu)	Annual Emissions (tpy)	Tons SO_2 Removed (tpy)
Baseline	0	0.45	452	NA
Wet FGD	80	0.09	90	362
Dry FGD	80	0.09	90	362
DSI	30	0.31	316	136

[A] Control efficiency is the lowest expected end of the range due to the combustion of low sulfur PRB coals and high relative flue gas flowrate for boiler design.

As indicated in Table 2, it is anticipated that the same level of SO_2 control can be achieved by the use of either Dry or Wet FGD spray dryer systems (non-DSI). This assumption is based on observation of FGD control in use on coal-fired utility boilers.

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[2] Karl B. Schnelle, Jr. and Charles A. Brown, Air Pollution Control Technology Handbook, CRC Press, 2002.

In general terms, removal of high concentrations of SO_2 in the flue gas is easily accomplished using either Dry or Wet FGD. Lower concentrations become more difficult to control and require greater amounts of reagent. Historically, Wet FGD systems have been used on higher-sulfur eastern coals, leading to higher efficiencies cited for Wet FGD systems, given there is much more sulfur to control. However, on lower-sulfur western coals (such as the PRB coal used at EGF) modern Dry FGD systems with better atomizer systems in conjunction with modern fabric filter technology can perform nearly as well as Wet FGD systems. Much of the final SO_2 control in a Dry FGD system takes place in the reagent-rich filter cake on the fabric filter.

Because of the equivalency in anticipated SO_2 emission rates, only Dry FGD technology is considered in this analysis. Dry FGD technology was selected as it has lower capital and operating costs than Wet FGD and will result in a more cost-effective approach. Furthermore, use of Wet FGD to control SO_2 emissions from the EGF boilers would result in both higher energy penalties to the facility operations and the generation of more waste byproducts than would Dry FGD. Increased energy penalties would be due to the additional pumps and water handling equipment required for slurry preparation for the Wet FGD, which would also lead to the creation of additional waste byproducts from the spent slurry. Dewatering of the spent slurry results in the production of a wastewater stream, as well as a waste sludge that must be disposed of in a landfill. Dry FGD results only in a dry product which is easily landfilled.

The lower control efficiencies of 80 and 30% anticipated for the Dry FGD and DSI systems, respectively, are based on the fact the EGF boilers combust low sulfur PRB coal and have relatively high flue gas flow rates associated with the OFA system, resulting in lower starting SO_2 concentrations. Additionally, because the boilers have a smaller than typical furnace size for the type of coal combusted, boiler slagging and maintenance is higher than typical. As a result, the introduction of large amounts of sorbent into the furnace and high temperature flue gas (such as with DSI systems) is anticipated to magnify these issues and result in a detrimental impact on operation and efficiency. Furthermore, frequent process load swings resulting from varying production demands presents difficulties with balancing sorbent injection and maintaining consistent control.

2.3.3 Evaluation of Impacts

The following sections present a detailed evaluation of the impacts of employing Dry FGD and DSI to control SO_2 emissions from the EGF boilers. The four factors assessed include: cost of compliance, energy, non-air quality environmental impacts and remaining useful life.

2.3.3.1 Cost of Compliance

Table 3 summarizes the capital and annual operating costs associated with retrofitting a Dry FGD and DSI system to each EGF boiler. Detailed cost estimates indicating data sources for each cost category have been included in Appendix A.

Table 3 – SO_2 Costs of Compliance (per boiler).

Description	Technology Option	
	Dry FGD w/Fabric Filter	DSI
Emission Rate (lb/MMBtu)	0.09	0.31
Emission Reduction (tpy)	362	136
Capital Cost ($)	24,188,700	5,302,000
Direct Annual Cost ($)	1,701,200	182,500
Indirect Annual Cost ($)	4,135,600	873,600
Total Annualized Cost ($)	5,836,800	1,056,100
Cost Effectiveness, per Boiler ($/ton)	16,100	7,800

2.3.3.2 Energy Impact

Use of Dry FGD or DSI to control SO_2 emissions from the EGF boilers would result in energy penalties to facility operations in the form of the electricity demand required for operation of ancillary equipment such as the reagent preparation and atomizer equipment, as well as additional backpressure on the exhaust system that results in decreased operational efficiency.

2.3.3.3 Non-Air Quality Environmental Impacts

The primary detrimental non-air quality environmental impact of a Dry FGD or DSI system is the creation of a solid waste byproduct from the spent reagent. Unlike Wet FGD, there is no wastewater stream resultant from the use of Dry FGD. The solid waste that is produced from a Dry FGD system can be landfilled or possibly used as an agricultural soil supplement depending on the fly ash content.

The DSI system is anticipated to greatly increase maintenance requirements as a result of increased boiler slagging and equipment fouling. Given the age of the existing boilers, the implementation of such a system may have a significant negative impact on remaining useful life.

2.3.3.4 Remaining Useful Life

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.

2.4 NO_x Analysis

Because the two coal-fired boilers at the EGF facility are identical, the analysis was prepared for one individual boiler. The results of the analysis can be applied equally to each boiler.

2.4.1 Identification of NO_x Control Technologies

Control of NO_x emissions from boilers can be attained through either the application of combustion controls or flue gas treatment (post-combustion) technologies. Combustion control processes can reduce the quantity of NO_x formed during the combustion process. Post-combustion technologies reduce the NO_x concentrations in the flue gas steam after the NO_x has been formed in the combustion process. These methods may be used alone or in combination to achieve the various degrees of NO_x emissions required.

2.4.1.1 Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) systems are an add-on flue gas treatment (post-combustion control technology) to control NO_x emissions. The SCR process involves the injection of a nitrogen-based reducing agent (reagent) such as ammonia (NH_3) or urea (CON_2H_4) to reduce the NO_x in the flue gas to N_2 and H_2O. The reagent is injected into the flue gas prior to passage through a catalyst bed, which accelerates the NO_x reduction reaction rate. Use of SCR results in small levels of NH_3 emissions (NH_3 slip). As the catalyst degrades, NH_3 slip will increase, ultimately requiring catalyst replacement.

Many types of catalysts, ranging from active metals to highly porous ceramics, are available for different applications. The type of catalyst chosen depends on several operational parameters, such as reaction temperature range, flue gas flow rate, fuel chemistry, catalyst activity and selectivity, operating life, and cost. Catalyst materials include, platinum (Pt), vanadium (V), titanium (Ti), tungsten (W), titanium oxide (TiO_2), zirconium oxide (ZrO_2), vanadium pentoxide (V_2O_5), silicon oxide (SiO_2), and zeolites (crystalline alumina silicates).

SCR systems can utilize aqueous NH_3, anhydrous NH_3, or a urea solution to produce NH_3 on demand. Aqueous NH_3 is generally transported and stored in concentrations ranging from 19% to 30% and therefore requires more storage capacity than anhydrous NH_3. Anhydrous NH_3 is nearly 100% pure in concentration and is a gas at normal atmospheric temperature and pressure. Anhydrous NH_3 must be stored and transported under pressure and when stored in quantities greater than 10,000 pounds, is subject to Risk Management Planning (RMP) requirements (40 CFR 68). The urea solution (urea and water at approximately 32% concentration) is used to form NH_3 on demand for injection into the flue gas. Generally, a specifically designed duct and decomposition chamber with a small supplemental burner is used to provide an appropriate temperature window and residence time to decompose urea to NH_3 and isocyanic acid (HNCO). Application of urea-based SCR systems to industrial boilers is a relatively new practice that is still under development.

Several different SCR system configurations have been used on utility boilers and are theoretically possible for use on smaller industrial boilers. In a high-dust SCR system, the reactor is located downstream of the economizer and upstream of the air heater, FGD system, and particulate control device. Low-dust SCR systems locate the reactor downstream of a particulate control device where the flue gas is relatively dust-free. Tail-end SCR systems locate the reactor downstream from all air pollution control equipment where most flue gas constituents detrimental to the SCR catalyst have been removed. However, tail-end SCR systems can require reheating of the flue gas to minimize condensation, leading to corrosion problems.

2.4.1.2 Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) is another method of post-combustion control. Similar to SCR, the SNCR process involves the injection of a nitrogen-based reducing agent (reagent) such as ammonia (NH_3) or urea to reduce the NO_x in the flue gas to N_2 and H_2O. However, the SNCR process works without the use of a catalyst. Instead, the SNCR process occurs within a combustion unit, which acts as the reaction chamber. The heat from the boiler combustion process provides the energy for the NO_x reduction reaction. Flue gas temperatures in the range of 1,500 to 1,900 °F, along with adequate reaction time within this temperature range, are required for this technology. SNCR is currently being used for NO_x emission control on some utility boilers, and can achieve NO_x reduction efficiencies of up to 75%. However, in typical industrial applications SNCR provides 30% to 50% NO_x reduction.

2.4.1.3 Combustion Controls

Combustion controls such as flue gas recirculation (FGR), reducing air preheat temperature (RAP), oxygen trim (OT), low excess air (LEA), over-fire air (OFA), staged combustion air (SCA), and low NO_x burners (LNB), can be used to reduce NO_x emissions depending on the type of boiler, characteristics of fuel and method of firing. In practice, combustion controls have not provided the same degree of NO_x controls as provided by add-on post combustion control technologies, but are generally used in conjunction with add-on controls, such as SNCR, to increase the NO_x removal efficiency. The EGF boilers are currently equipped with modern OFA control systems.

2.4.2 NO_x Control Technology Effectiveness

Effectiveness is measured by the amount of NO_x removed by each control technology based on a comparison of the controlled emission rates to the baseline emission rates of the boilers. Table 4 provides a summary of the NO_x control technology effectiveness.

Table 4 – NO_x Control Technology Effectiveness.

Control Technology	Percent NO_x Reduction	Emission Rate (lb/MMBtu)	Annual Emissions (tpy)	Tons NO_x Removed (tpy)
Baseline/OFA	0	0.34	340	NA
SCR	80	0.07	68	272
SNCR	30	0.26	238	102

The lower control efficiencies of 80 and 30% anticipated for the SCR and SNCR systems, respectively, are based on the fact the EGF boilers are equipped with modern OFA control systems that work to reduce the starting NO_x concentration. Furthermore, the boilers have a smaller than typical furnace size for the type of coal combusted and flue gas flow rates that are higher than typical. This operational characteristic, when combined with frequent process load swings resulting from varying production demands, results in variable flue gas temperature ranges within the boiler furnace and presents difficulties with balancing reagent injection and maintaining consistent control.

2.4.3 Evaluation of Impacts

The following sections present a detailed evaluation of the impacts of employing the feasible control technologies to control NO_x emissions from the EGF boilers. The four factors assessed include: cost of compliance, energy, non-air quality environmental impacts and remaining useful life.

2.4.3.1 Cost of Compliance

Table 5 summarizes the capital and annual operating costs associated with retrofitting NO_x control systems to each EGF boiler. Detailed cost estimates indicating data sources for each cost category have been included in Appendix A.

Table 5 – NO_x Cost of Compliance (per Boiler).

Description	**Technology Option**	
	SCR	**SNCR**
Emission Rate (lb/MMBtu)	0.07	0.26
Emission Reduction (tpy)	272	102
Capital Cost ($)	21,572,000	4,090,400
Direct Annual Cost ($)	246,200	89,200
Indirect Annual Cost ($)	2,980,900	584,100
Total Annualized Cost ($)	3,245,100	673,300
Cost Effectiveness, per Boiler ($/ton)	11,900	6,600

2.4.3.2 Energy Impact

The application of SCR and SNCR systems would result in energy penalties in the form of electricity demand for required operation of ancillary equipment such as reagent preparation and delivery, as well as additional backpressure on the exhaust system that results in decreased operational efficiency.

2.4.3.3 Non-Air Quality Environmental Impacts

SCR and SNCR both require some form of ammonia (NH_3) source for operation. This can be stored in liquid, solid or gas, and processed on site for use. Depending on quantities stored, risk management requirements may apply. Both systems are also prone to NH_3 slip from unreacted NH_3. This will result in the emission of an additional pollutant.

2.4.3.4 Remaining Useful Life

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.

Appendix A

Cost Calculations

Dry FGD Capital Cost Summary

Description of Cost	**($)**[A]	**Remarks**
Direct Capital Costs		
Dry FGD Equipment[B]	4,740,100	Scaled Quote
Control/Instrumentation[C]	474,000	10% of Equipment Cost
Sales Tax	284,400	6% of Equipment Cost
Freight[C]	237,000	5% of Equipment Cost
Total Equipment Cost (TEC)	**5,735,500**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	4,875,200	Based on percentage of TEC: 12% Foundation & Supports, 40% Erection, 1% Electrical Installation, 30% Piping, 1% Painting, 1% Insulation
Site Preparation[D]	1,000,000	Estimated
Total Direct Investment (TDI)	11,610,700	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
Contingency	172,100	3% of TEC
Engineering	573,600	10% of TEC
Construction & Field Expense	573,600	10% of TEC
Contractor Fees	573,600	10% of TEC
Start-up Assistance	57,400	1% of TEC
Performance Test	57,400	1% of TEC
Total Indirect Investment (TII)	**2,007,700**	

Total Turnkey Cost (TTC)	**13,618,400**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor and scaled from similar projects.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

Dry FGD Fabric Filter Capital Cost Summary

Description of Cost	**($)[A]**	**Remarks**
Direct Capital Costs		
Dry FGD Equipment[B]	3,611,500	Scaled Quote
Control/Instrumentation[C]	361,200	10% of Equipment Cost
Sales Tax	216,700	6% of Equipment Cost
Freight[C]	180,600	5% of Equipment Cost
Total Equipment Cost (TEC)	**4,370,000**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	3,233,800	Based on percentage of TEC: 4% Foundation & Supports, 50% Erection, 8% Electrical Installation, 1% Piping, 4% Painting, 7% Insulation
Site Preparation[D]	1,000,000	Estimated
Total Direct Investment (TDI)	8,603,800	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
Contingency	131,100	3% of TEC
Engineering	437,000	10% of TEC
Construction & Field Expense	874,000	20% of TEC
Contractor Fees	437,000	10% of TEC
Start-up Assistance	43,700	1% of TEC
Performance Test	43,700	1% of TEC
Total Indirect Investment (TII)	**1,966,500**	

Total Turnkey Cost (TTC)	**10,570,300**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor and scaled from similar projects.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

Dry FGD/Fabric Filter Annual Cost Summary

Description of Cost	($)[A]	Remarks
Direct Annual Costs [B]		
Dry FGD Labor	49,300	1 hr per shift, assumed 8 hr shifts
Dry FGD Supervisor	7,400	15% of labor
Fabric Filter Labor	65,700	2 hr per shift, assumed 8 hr shifts
Fabric Filter Supervisor	9,900	15% of labor
Solvent (Reagent)	457,900	Consumption x cost
Fabric Filter Bag Replacement	304,900	Labor plus bag cost
Solids Scrubber Disposal	100,300	Production x cost
Solids Fly Ash Disposal	168,000	Production x cost
Maintenance Labor, Dry FGD	49,300	1 hr per shift, assumed 8 hr shifts
Maintenance Material, Dry FGD	49,300	100% of labor
Maintenance Labor, Fabric F.	65,700	2 hr per shift, assumed 8 hr shifts
Maintenance Material, Fabric F.	65,700	100% of labor
Induced Draft Fan	231,100	Consumption x cost
Pump	76,700	Consumption x cost
Direct Annual Costs (DAC)	**1,701,200**	

Indirect Annual Costs [C]		
Overhead	675,100	60% of O&M Labor
Administrative Charges	483,800	2% of Total Capital Investment
Property Taxes	241,900	1% of Total Capital Investment
Insurance	241,900	1% of Total Capital Investment
Dry FGD Annualized Costs[D]	1,495,200	(Capital Investment) x (CFR of 0.10979)
Fabric Filter Annualized Costs[E]	997,700	(Capital Investment) x (CFR of 0.09439)
Indirect Annual Costs (IAC)	**4,135,600**	

Total Annualized Costs (TAC)	**5,836,800**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs are based on site-specific design parameters.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers and fabric filters.

[D] Capital Recovery Factor (CFR) based on 15 year life and an interst rate of 7%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

[E] Capital Recovery Factor (CFR) based on 20 year life and an interst rate of 7%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

Dry Sorbent Injection Capital Cost Summary

Description of Cost	($)[A]	Remarks
Direct Capital Costs		
Dry FGD Equipment[B]	1,865,000	Vendor Quote
Control/Instrumentation[C]	186,500	10% of Equipment Cost
Sales Tax	111,900	6% of Equipment Cost
Freight[C]	93,300	5% of Equipment Cost
Total Equipment Cost (TEC)	**2,256,700**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	1,918,200	Based on percentage of TEC: 12% Foundation & Supports, 40% Erection, 1% Electrical Installation, 30% Piping, 1% Painting, 1% Insulation
Site Preparation[D]	450,000	Estimated (includes electrical upgrade)
Total Direct Investment (TDI)	4,624,900	**TEC + TIC + Site Prep. = TDI**
Indirect Capital Cost [C]		
Contingency	67,700	3% of TEC
Engineering	112,800	5% of TEC
Construction & Field Expense	225,700	10% of TEC
Contractor Fees	225,700	10% of TEC
Start-up Assistance	22,600	1% of TEC
Performance Test	22,600	1% of TEC
Total Indirect Investment (TII)	**677,100**	
Total Turnkey Cost (TTC)	**5,302,000**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

Dry Sorbent Injection Annual Cost Summary

Description of Cost	**($)**[A]	**Remarks**
Direct Annual Costs [B]		
DSI Labor	24,600	1/2 hr per shift, assumed 8 hr shifts
DSI Supervisor	3,700	15% of labor
Solvent (Trona)	55,000	Consumption x cost
Solids Fly Ash Disposal	27,000	Production x cost
Maintenance Labor	24,600	1/2 hr per shift, assumed 8 hr shifts
Maintenance Material, Dry FGD	24,600	100% of labor
Induced Draft Fan/Pumps	23,000	Consumption x cost
Direct Annual Costs (DAC)	**182,500**	

Indirect Annual Costs [C]		
Overhead	79,500	60% of O&M Labor
Administrative Charges	106,000	2% of Total Capital Investment
Property Taxes	53,000	1% of Total Capital Investment
Insurance	53,000	1% of Total Capital Investment
Dry FGD Annualized Costs[D]	582,100	(Capital Investment) x (CFR of 0.10979)
Indirect Annual Costs (IAC)	**873,600**	

Total Annualized Costs (TAC)	**1,056,100**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs are based on site-specific design parameters and vendor quote.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers and fabric filters.

[D] Capital Recovery Factor (CFR) based on 15 year life and an interst rate of 7%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

Selective Catalytic Reduction Capital Cost Summary

Description of Cost	($)[A]	Remarks
Direct Capital Costs		
SCR Equipment[B]	10,006,000	Control Cost Manual Spreadsheet
Reagent Preparation Cost[B]	1,980,500	Control Cost Manual Spreadsheet
Control/Instrumentation[C]	1,000,600	10% of Equipment Cost
Sales Tax	600,400	6% of Equipment Cost
Freight[C]	500,300	5% of Equipment Cost
Total Equipment Cost (TEC)	**14,087,800**	
Total Installation Cost (TIC)/Balance of Plant Cost[B]	2,796,900	Control Cost Manual Spreadsheet
Site Preparation[D]	500,000	Demo and Equipment Relocation
Total Direct Investment (TDI)	**17,384,700**	**TEC + TIC + Site Prep. = TDI**
Indirect Capital Cost [C]		
Contingency	422,600	3% of TEC
Engineering	1,408,800	10% of TEC
Construction & Field Expense	704,400	5% of TEC
Contractor Fees	1,408,800	10% of TEC
Start-up Assistance	281,800	2% of TEC
Performance Test	140,900	1% of TEC
Total Indirect Investment (TII)	**4,367,300**	
Total Turnkey Cost (TTC)	**21,752,000**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost obtained from EPA Air Pollution Control SCR Spreadsheet.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002.

[D] Estimated by HDR.

Selective Catalytic Reduction Annual Cost Summary

Description of Cost	**($)[A]**	**Remarks**
Direct Annual Costs [B]		
Annual SCR Maintenance	96,100	Control Cost Manual Spreadsheet
Reagent (Ammonia)	28,000	Control Cost Manual Spreadsheet
SCR Electricity	76,600	Control Cost Manual Spreadsheet
Catalyst Replacment	63,500	Control Cost Manual Spreadsheet
Direct Annual Costs (DAC)	**264,200**	

Indirect Annual Costs [C]		
Overhead	57,700	60% of O&M Labor
Administrative Charges	435,000	2% of Total Capital Investment
Property Taxes	217,500	1% of Total Capital Investment
Insurance	217,500	1% of Total Capital Investment
Dry FGD Annualized Costs[D]	2,053,200	(Capital Investment) x (CFR of 0.09439)
Indirect Annual Costs (IAC)	**2,980,900**	

Total Annualized Costs (TAC)	**3,245,100**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs obtained from EPA Air Pollution Control SCR Spreadsheet.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for incinerators and oxidizers.

[D] Capital Recovery Factor (CFR) based on 20 year life and an interst rate of 7%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

Selective Non-Catalytic Reduction Capital Cost Summary

Description of Cost	($)[A]	Remarks
Direct Capital Costs		
SNCR Equipment[B]	1,196,500	Control Cost Manual Spreadsheet
Control/Instrumentation[C]	119,700	10% of Equipment Cost
Sales Tax	71,800	6% of Equipment Cost
Freight[C]	59,800	5% of Equipment Cost
Total Equipment Cost (TEC)	**1,447,800**	
Total Installation Cost (TIC)/Balance of Plant Cost[B]	1,743,700	Control Cost Manual Spreadsheet
Site Preparation[D]	450,000	Demo and Equipment Relocation
Total Direct Investment (TDI)	**3,641,500**	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
Contingency	43,400	3% of TEC
Engineering	144,800	10% of TEC
Construction & Field Expense	72,400	5% of TEC
Contractor Fees	144,800	10% of TEC
Start-up Assistance	29,000	2% of TEC
Performance Test	14,500	1% of TEC
Total Indirect Investment (TII)	**448,900**	

Total Turnkey Cost (TTC)	**4,090,400**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost obtained from EPA Air Pollution Control SNCR Spreadsheet.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002.

[D] Estimated by HDR.

Selective Non-Catalytic Reduction Annual Cost Summary

Description of Cost	**($)**[A]	**Remarks**
Direct Annual Costs [B]		
Annual SNCR Maintenance	57,300	Control Cost Manual Spreadsheet
Reagent (Ammonia)	26,400	Control Cost Manual Spreadsheet
Electricity	1,700	Control Cost Manual Spreadsheet
Water	600	Control Cost Manual Spreadsheet
Additional Fuel	3,000	Control Cost Manual Spreadsheet
Additional Ash	200	Control Cost Manual Spreadsheet
Direct Annual Costs (DAC)	**89,200**	
Indirect Annual Costs [C]		
Overhead	34,400	60% of O&M Labor
Administrative Charges	81,800	2% of Total Capital Investment
Property Taxes	40,900	1% of Total Capital Investment
Insurance	40,900	1% of Total Capital Investment
Dry FGD Annualized Costs[D]	386,100	(Capital Investment) x (CFR of 0.09439)
Indirect Annual Costs (IAC)	**584,100**	
Total Annualized Costs (TAC)	**673,300**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs obtained from EPA Air Pollution Control SCR Spreadsheet.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for incinerators and oxidizers.

[D] Capital Recovery Factor (CFR) based on 20 year life and an interst rate of 7%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

Regional Haze Four Factor Analysis

American Crystal Sugar Company

East Grand Forks, MN

For Submittal to:
Minnesota Pollution Control Agency
520 Lafayette Road North
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Appendix A. Cost Calculations

1 Introduction

In response to the Minnesota Pollution Control Agency (MPCA) Request for Information (ROI) dated February 14, 2020 and the subsequent comments received by e-mail on March 8, 2021, American Crystal Sugar Company (ACSC) is providing the following revised Four Factor Analysis to address pollutants of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emitted from the coal-fired boilers at the East Grand Forks (EGF) facility.

This analysis is being provided for planning purposes and is based on budgetary cost information obtained from scaled vendor quotes for similar systems as well as methodology presented in the U.S. Environmental Protection Agency's (EPA) Air Pollution Control Cost Manual. This approach is intended to provide a study-level estimate (+/-30%) of capital and annual costs. In the event that emission reductions will be proposed for inclusion in the State Implementation Plan (SIP), it is requested that ACSC be given the opportunity to further refine the cost data to incorporate site-specific quotes reflecting current market conditions and unique site physical constraints.

1.1 Analysis Methodology

Following the U.S. Environmental Protection Agency (EPA) *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 20, 2019, the Four Factor Analysis addresses:

- The costs of compliance;
- The time necessary for compliance;
- The energy and non-air quality environmental impacts of compliance; and,
- The remaining useful life of the source(s).

The first step in the process is identification of all available retrofit technologies for each pollutant (SO_2 and NO_x). Control options that are technically infeasible are eliminated and remaining options are evaluated to determine their control effectiveness and economic, energy and environmental impacts.

Technically feasible control technologies are ranked in the order of highest expected emission reduction to lowest expected emission reduction and are evaluated following a "top-down" approach similar to Best Available Control Technology (BACT) analyses.

Impacts considered for each control technology include: cost of compliance, energy impacts, non-air quality environmental impacts and the remaining useful life of the unit to be controlled.

1.2 EGF Source Parameters

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 electrostatic precipitators (ESPs) to control particulate matter emissions. The boilers and ESP systems were originally constructed in 1975. However, in 2013 both boilers were modified to install new OFA systems to control carbon monoxide (CO) and NO_x emissions in advance of the forthcoming 40 CFR 63, Subpart DDDDD, industrial boiler national emission standards. Additionally, the ESPs were extensively upgraded in 2014. Upgrades included flow modifications to better distribute flue gas flow, rebuilding of collection plates and electrodes, and upgrades to optimize power supplies and controls.

The maximum rated heat input of each boiler is 356 million British thermal units per hour (MMBtu/hr). During normal operations, the boilers typically operate between 70 and 80 percent capacity depending on processing demands. 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). Given the campaign constraints, the typical annual heat input for each of the boilers is around 1,800,000 MMBtu/yr.

The boilers combust low sulfur subbituminous coal from the Powder River Basin (PRB). 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.

The boilers are identified as EU001 and EU002 in Air Emission Permit No. 11900002-006. The operating permit limits each boiler to maximum SO_2 emissions of 391.8 lb/hr (1.10 lb/MMBtu) and NO_x emissions of 227.9 lb/hr (0.64 lb/MMBtu).

As indicated in the EPA's *Guidance on Regional Haze State Implementation Plans*, a state may use a source's annual emissions in tons to determine actual visibility impacts. Therefore, actual emission levels based on source test data were used to characterize emissions-related factors in this analysis. The average SO_2 emission rate from the EGF boilers as reported in the most recent emission inventory is 0.45 lb/MMBtu and 452 tons per year (tpy) for each boiler. The average NO_x emission rate from the EGF boilers as reported in the most recent emission inventory is 0.34 lb/MMBtu and 340 tpy for each boiler.

Because the boilers are of identical size and type, control technology costs and design features would be the same for both boilers. It is anticipated that the Four Factor Analysis applies to the EGF facility as a whole, and potential control technology determinations would not be made for a single boiler, but instead would apply to both boilers at the facility. Therefore, the average emission rate for the two boilers was used in the analysis to determine costs of compliance.

2 Four Factor Analysis

2.1 Applicable Pollutants

The Four Factor Analysis addresses criteria pollutants of SO_2 and NO_x.

SO$_2$ Formation. SO_2 emissions are formed from the oxidation of organic sulfur and pyritic sulfur in the coal during the combustion process. The majority of sulfur is oxidized to SO_2, however, a small quantity may be further oxidized to form sulfur trioxide (SO_3). Approximately 90% of the sulfur present in the subbituminous coal will be emitted as sulfur oxides (SO_x) compounds. Alkaline ash from some coals (including PRB coals) may cause some of the sulfur to react in the furnace to form various sulfate salts that are then retained in the fly ash. Sulfuric acid mist (H_2SO_4) forms when SO_2 emissions react with moisture and oxygen in the environment.

NO$_x$ Formation. There are two primary mechanisms of NO_x formation in coal-fired industrial boilers: thermal production of NOx from atmospheric nitrogen and oxygen, and oxidation of nitrogen bound in the fuel. High combustion temperatures cause the nitrogen (N_2) and oxygen (O_2) molecules in the combustion air to react and form thermal NO_x. Because thermal NO_x is primarily a function of combustion temperature, NO_x emission rates vary with burner and source design. Experimental measurements of thermal NO_x formation have shown that the NO_x concentration is exponentially dependent on temperature and is proportional to the N_2 concentration in the flame, the square root of the O_2 concentration in the flame, and the gas residence time[1]. The formation of fuel NO_x from reactions of fuel bound nitrogen and air can account for up to 80% of total NO_x from coal combustion. Subbituminous coals contain from 0.5 to 2 percent by weight fuel-bound nitrogen.

2.2 Economic Evaluation Criteria

Costs of compliance are directly related to the technically feasible control technology option selected and the level of emission reduction experienced from the control. Costs are expressed in terms of dollars per ton of pollutant removed, where the cost is the annualized capital and operating costs, and the tons of pollutant removed is the incremental reduction in pollutant emissions over current baseline (actual) emission levels.

Base economic criteria used in this analysis are listed in Table 1.

Table 1 – Economic Evaluation Criteria.

Economic Parameter	Value
Interest Rate, percent	5[A]
Control Equipment Economic Life, years	20[B]
Base Labor Cost, $/hr	60[C]
Energy Cost, $/kW-hr	0.06[D]

[A] Current ACSC rate for capital improvement project financing.
[B] EPA Memorandum, Calculating Amortized Capital Costs, July 24, 1987,
Robert D. Bauman, Chief, Standards and Implementation Branch.
[C] Loaded labor rate obtained from ACSC.
[D] Actual ACSC electricity cost.

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[1] AP42, Chapter 1, Bituminous and Subbituminous Coal Combustion, (9/98).

Cost estimates used in the analysis have been compile from a number of data sources. In general, the cost estimates were performed following guidance provided in the EPA Air Pollution Control Cost Manual, Seventh Edition, January 2017. The EPA control cost manual data was supplemented with vendor supplied quotations when available and general engineering estimates. Detailed cost estimate and support data have been provided in Appendix A.

2.3 SO_2 Analysis

Because the two coal-fired boilers at the EGF facility are identical, the analysis was prepared for one individual boiler. The results of the analysis can be applied equally to each boiler.

2.3.1 Identification of SO_2 Control Technologies

Control of SO_2 emissions from fuel-combustion sources can be accomplished through two approaches: removal of elemental sulfur from the fuel prior to combustion, and flue gas desulfurization (FGD), which consists of removal of SO_2 from flue gas after combustion (post-combustion control).

Many oil refineries operate catalyst-based desulfurization units to remove organic sulfur from liquid crude oil. However, in solid fuels, such as coal, a significant fraction of the sulfur is in the form of pyrite (FeS_2) or other mineral sulfates. It is possible to remove some mineral sulfates through physical processes such as washing and/or chemical processing. However, desulfurization of solid fuels is generally viewed as inefficient and expensive. Additionally, organic sulfur cannot be removed by physical cleaning. It is unlikely that sufficient desulfurization of solid fuels can be accomplished to meet anticipated emission requirements. Therefore removal of sulfur from the coal prior to combustion will not be considered a viable option for this analysis.

FGD technologies can be divided into two main categories: regenerative and throwaway processes. Regenerative processes recover sulfur in a usable form that can be sold as a reusable sulfur product. Throwaway processes remove sulfur from flue gas and scrubber byproducts are subsequently discarded. All of the FGD technologies considered can achieve SO_2 removal efficiencies of 90 to 95% depending on the amount of sulfur in the coal. For relatively high sulfur coals, removal efficiencies can exceed 95%, while for lower sulfur coals (such as PRB), the achievable removal efficiency is typically less than 95%.

Regenerative processes, by nature, contain a regeneration step in the FGD process that results in higher costs than throwaway processes due to equipment and operation expenses. However, in instances where disposal options are limited and markets for recovered sulfur products are readily available, regenerative processes may be used. Potential regenerative processes that are available include the Wellman-Lord (W-L) process, magnesium oxide process, citrate scrubbing process, Flakt-Boliden process, aqueous carbonate process, Sulf-X process, Conosox process, Westvaco process and adsorption of SO_2 by a bed of copper oxide.

Throwaway processes such as limestone scrubbing have become widely accepted by the coal-fired power industry for FGD because limestone scrubbers have overall lower costs and are simpler to operate than regenerative processes. Because the throwaway process can achieve the same removal efficiencies as regenerative processes and cost less, this analysis for SO_2 will focus on throwaway processes and further discussion of regenerative processes will not be considered.

Throwaway processes can be divided into two categories, wet and dry. Wet or dry refers to the state of the waste by-products. Both wet and dry technologies have advantages and disadvantages with respect to initial capital and operational expenses.

2.3.1.1 Wet FGD Systems

Wet scrubbing (wet FGD) systems used for SO_2 reduction typically consist of the following operations: scrubbing or absorption, lime handling and slurry preparation, sludge processing, and flue gas handling.

Wet FGD technology is a well-established process for removing SO_2 from flue gas. In wet scrubbers, the flue gas enters a spray tower or absorber where it is sprayed with a water slurry, which is approximately 10 percent lime or limestone. Sodium alkali solutions can also be used in FGD systems, however these processes are considerably more expensive than lime. The preferred sorbents are limestone and lime, respectively, due to the availability and relatively low cost of limestone. Calcium in the slurry reacts with the SO_2 in the flue gas to form calcium sulfite or calcium sulfate. The overall chemical reaction can be simply expressed as:

$$SO_2 + CaCO_3 \rightarrow CaSO_3 + CO_2$$

Spent slurry from the reaction tank is pumped into a thickener where solids settle before being filtered for final dewatering to approximately 50 percent solids. Water removed during this process is sent to a process water holding tank, which eventually will require wastewater treatment. In a non-regenerative system, the waste sludge must also be disposed of properly. Finally, scrubbed flue gases are directed through a stack gas reheater in order to minimize corrosion downstream of the scrubber due to conversion of SO_2 to SO_3 and subsequently sulfuric acid (H_2SO_4). Reheating is sometimes needed for proper drafting and rise of exhaust gases out the stack, as well as minimizing condensation. As an alternative, the stack can be constructed of acid resistant material.

Most wet FGD systems have two stages: one for fly ash removal and one for SO_2 removal. The flue gas normally passes first through a fly ash removal device, either an electrostatic precipitator (ESP) or a bag filter, and then into the SO_2 absorber. There are many different types of absorbers that can be used in wet FGD systems, including: spray towers, venturis, plate towers, and mobile packed beds. However, many of these systems can result in scale buildup, plugging or erosion, which can affect the dependability and efficiency of the absorber. Therefore, simple scrubbers such as spray towers are commonly used. The chief drawback of the spray tower design is that it requires a higher liquid-to-gas ratio for equivalent removal of SO_2 than other absorber designs.

2.3.1.2 Dry FGD Systems

In contrast to wet scrubbing systems, dry FGD (spray dryer) systems use much smaller amounts of liquid. With a spray dryer system, the flue gases enter an absorbing tower (dryer) where the hot gases are contacted with a finely atomized slurry, which is usually a calcium-based sorbent such as calcium hydroxide or calcium oxide (lime). Acid gases and SO_2 are absorbed by the slurry mixture and react to form solid salts. The heat of the flue gas evaporates the water droplets in the sprayed slurry, and a non-saturated flue gas exits the absorber tower. The absorption process is also somewhat temperature dependent. Cooler flue gases allow the acid gases to more effectively react with the sorbents. The overall chemical reactions can be simply expressed as:

$$Ca(OH)_2 + SO_2 \rightarrow CaSO_3(s) + H_2O$$

$$Ca(OH)_2 + 2HCl \rightarrow CaCl_2\ (s) + 2H_2O$$

As can be seen above, one mole of calcium hydroxide will neutralize one mole of SO_2, whereas one mole of calcium hydroxide will neutralize two moles of hydrochloric acid (HCl). A similar reaction occurs with the neutralization of hydrofluoric acid (HF). These reactions demonstrate that when using a spray dryer the HCl and HF are removed more readily than SO_2. Reagent requirements should consider that the HCl and HF are removed first, followed by the reagent quantity required to remove the SO_2[2].

The heat of the flue gas evaporates the water droplets in the sprayed slurry, and a non-saturated flue gas exists the absorber tower. The exhaust stream exiting the absorber contains fly ash, calcium salts, and un-reacted lime, which must be sent to a particulate control device such as a fabric filter (baghouse). The particulate control device not only is necessary to control particulate matter, but also aids in acid-gas removal. Acid gases are removed when the flue gas comes in contact with the lime-containing particles on the surface of the ESP or baghouse. Fabric filters are considered to have slightly higher residual acid gas removal levels than ESPs because the acid gases must pass through the lime-containing filter cake in a fabric filter system. Modern dry FGD systems include a loop to recycle a portion of the baghouse-collected material for re-use in the FGD module because this material contains a relatively high amount of unreacted lime.

A lower efficiency Dry FGD process that utilizes either wet or dry reagent injected directly into the furnace or flue gas duct is known as dry sorbent injection (DSI). In general, hydrated lime, lime slurry or powdered lime is injected into the existing furnace or ductwork. The constraints of the existing furnace and ductwork configuration may limit expected retrofit control efficiencies of SO_2, which range from 50 to 80%. A significant drawback of this type of system is the increased maintenance costs incurred from directly injecting a sorbent into the furnace and associated duct work and the potential to significantly reduce the useful life of the boiler. Although DSI is a type of Dry FGD process, it will be referred to separately in this analysis.

2.3.2 SO_2 Control Technology Effectiveness

Effectiveness is measured by the amount of SO_2 removed from each control technology based on a comparison of the controlled emission rates to the baseline emission rates of the boilers. Table 2 provides a summary of the SO_2 control technology effectiveness.

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[2] Karl B. Schnelle, Jr. and Charles A. Brown, Air Pollution Control Technology Handbook, CRC Press, 2002.

Table 2 – SO_2 Control Technology Effectiveness.

Control Technology	Percent SO_2 Reduction[A]	Emission Rate (lb/MMBtu)	Annual Emissions (tpy)	Tons SO_2 Removed (tpy)
Baseline	0	0.450	452	NA
Wet FGD	90	0.045	45	407
Dry FGD	85	0.068	68	384
DSI	50	0.225	226	226

[A] Control efficiency is the lowest expected end of the range due to the combustion of low sulfur PRB coals and high relative flue gas flowrate for boiler design.

As indicated in Table 3, it is anticipated that nearly the same level of SO_2 control can be achieved by the use of either Dry or Wet FGD spray dryer systems (non-DSI). This assumption is based on observation of FGD control in use on coal-fired utility boilers.

In general terms, removal of high concentrations of SO_2 in the flue gas is easily accomplished using either Dry or Wet FGD. Lower concentrations become more difficult to control and require greater amounts of reagent. Historically, Wet FGD systems have been used on higher-sulfur eastern coals, leading to higher efficiencies cited for Wet FGD systems, given there is much more sulfur to control. However, on lower-sulfur western coals (such as the PRB coal used at CRK) modern Dry FGD systems with better atomizer systems in conjunction with modern fabric filter technology can perform as well as Wet FGD systems. Much of the final SO_2 control in a Dry FGD system takes place in the reagent-rich filter cake on the fabric filter.

Because of the equivalency in anticipated SO_2 emission rates, only Dry FGD technology is considered in this analysis. Dry FGD technology was selected as it has lower capital and operating costs than Wet FGD and will result in a more cost-effective approach. Wet FGD systems have been historically used on large sources greater than 3,000 MMBtu/hr (EPA Fact Sheet, EPA-452/F-03-034). On larger systems, the greater capital and operating costs can be more easily justified due to the greater mass of pollutants removed. Additional equipment such as water/slurry handling, slaking, waste handling, reaction chamber size, stack flue gas reheating and corrosive resistant materials, contribute to the higher capital equipment costs for Wet FGD systems.

Furthermore, use of Wet FGD to control SO_2 emissions from the EGF boilers would result in both higher energy penalties to the facility operations and the generation of more waste byproducts than would Dry FGD. Increased energy penalties would be due to the additional pumps and water handling equipment required for slurry preparation for the Wet FGD, which would also lead to the creation of additional waste byproducts from the spent slurry. Dewatering of the spent slurry results in the production of a wastewater stream, as well as a waste sludge that must be disposed of in a landfill. Dry FGD results only in a dry product which is easily landfilled.

The lower control efficiency of 50% anticipated for the DSI system is based on the fact the EGF boilers combust low sulfur PRB coal and have relatively high flue gas flow rates associated with the OFA system, resulting in lower starting SO_2 concentrations. Additionally, the boilers were originally designed to burn lignite coal, but were switched to subbituminous coal in the mid-1980s. As a result, the boilers have a smaller than typical furnace size for the type of coal combusted. This leads to higher combustion air flowrates, short residence times in the furnace, and boiler slagging and maintenance issues. The introduction of large amounts of sorbent into the furnace and high temperature flue gas (such as with DSI systems) is anticipated to magnify these issues and result in a detrimental impact on operation and efficiency. Furthermore, frequent process load swings resulting from varying production demands presents difficulties with balancing sorbent injection and maintaining consistent control.

2.3.3 Evaluation of Impacts

The following sections present a detailed evaluation of the impacts of employing Dry FGD and DSI to control SO_2 emissions from the EGF boilers. The four factors assessed include: cost of compliance, energy, non-air quality environmental impacts and remaining useful life.

2.3.3.1 Cost of Compliance

Table 3 summarizes the capital and annual operating costs associated with retrofitting a Dry FGD and DSI system to each EGF boiler. Detailed cost estimates indicating data sources for each cost category have been included in Appendix A.

Table 3 – SO_2 Costs of Compliance (per boiler).

Description	**Technology Option**	
	Dry FGD w/Fabric Filter	**DSI**
Emission Rate (lb/MMBtu)	0.068	0.225
Emission Reduction (tpy)	384	226
Capital Cost ($)	27,199,600	4,072,500
Direct Annual Cost ($)	1,701,200	182,500
Indirect Annual Cost ($)	3,945,600	576,500
Total Annualized Cost ($)	5,646,800	759,000
Cost Effectiveness, per Boiler ($/ton)	14,700	3,400

2.3.3.2 Energy Impact

Use of Dry FGD or DSI to control SO_2 emissions from the EGF boilers would result in energy penalties to facility operations in the form of the electricity demand required for operation of ancillary equipment such as the reagent preparation and atomizer equipment, as well as additional backpressure on the exhaust system that results in decreased operational efficiency.

2.3.3.3 Non-Air Quality Environmental Impacts

The primary detrimental non-air quality environmental impact of a Dry FGD or DSI system is the creation of a solid waste byproduct from the spent reagent. Unlike Wet FGD, there is no wastewater stream resultant from the use of Dry FGD. The solid waste that is produced from a Dry FGD system can be landfilled or possibly used as an agricultural soil supplement depending on the fly ash content.

The DSI system is anticipated to greatly increase maintenance requirements as a result of increased boiler slagging and equipment fouling. Given the age of the existing boilers, the implementation of such a system may have a significant negative impact on remaining useful life.

2.3.3.4 Remaining Useful Life

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.

2.4 NO_x Analysis

Because the two coal-fired boilers at the EGF facility are identical, the analysis was prepared for one individual boiler. The results of the analysis can be applied equally to each boiler.

2.4.1 Identification of NOx Control Technologies

Control of NO_x emissions from boilers can be attained through either the application of combustion controls or flue gas treatment (post-combustion) technologies. Combustion control processes can reduce the quantity of NO_x formed during the combustion process. Post-combustion technologies reduce the NO_x concentrations in the flue gas steam after the NO_x has been formed in the combustion process. These methods may be used alone or in combination to achieve the various degrees of NO_x emissions required.

2.4.1.1 Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) systems are an add-on flue gas treatment (post-combustion control technology) to control NO_x emissions. The SCR process involves the injection of a nitrogen-based reducing agent (reagent) such as ammonia (NH_3) or urea (CON_2H_4) to reduce the NO_x in the flue gas to N_2 and H_2O. The reagent is injected into the flue gas prior to passage through a catalyst bed, which accelerates the NO_x reduction reaction rate. Use of SCR results in small levels of NH_3 emissions (NH_3 slip). As the catalyst degrades, NH_3 slip will increase, ultimately requiring catalyst replacement.

Many types of catalysts, ranging from active metals to highly porous ceramics, are available for different applications. The type of catalyst chosen depends on several operational parameters, such as reaction temperature range, flue gas flow rate, fuel chemistry, catalyst activity and selectivity, operating life, and cost. Catalyst materials include, platinum (Pt), vanadium (V), titanium (Ti), tungsten (W), titanium oxide (TiO_2), zirconium oxide (ZrO_2), vanadium pentoxide (V_2O_5), silicon oxide (SiO_2), and zeolites (crystalline alumina silicates).

SCR systems can utilize aqueous NH_3, anhydrous NH_3, or a urea solution to produce NH_3 on demand. Aqueous NH_3 is generally transported and stored in concentrations ranging from 19% to 30% and therefore requires more storage capacity than anhydrous NH_3. Anhydrous NH_3 is nearly 100% pure in concentration and is a gas at normal atmospheric temperature and pressure. Anhydrous NH_3 must be stored and transported under pressure and when stored in quantities greater than 10,000 pounds, is subject to Risk Management Planning (RMP) requirements (40 CFR 68). The urea solution (urea and water at approximately 32% concentration) is used to form NH_3 on demand for injection into the flue gas. Generally, a specifically designed duct and decomposition chamber with a small supplemental burner is used to provide an appropriate temperature window and residence time to decompose urea to NH_3 and isocyanic acid (HNCO). Application of urea-based SCR systems to industrial boilers is a relatively new practice that is still under development.

Several different SCR system configurations have been used on utility boilers and are theoretically possible for use on smaller industrial boilers. In a high-dust SCR system, the reactor is located downstream of the economizer and upstream of the air heater, FGD system, and particulate control device. Low-dust SCR systems locate the reactor downstream of a particulate control device where the flue gas is relatively dust-free. Tail-end SCR systems locate the reactor downstream from all air pollution control equipment where most flue gas constituents detrimental to the SCR catalyst have been removed. However, tail-end SCR systems can require reheating of the flue gas to minimize condensation, leading to corrosion problems.

2.4.1.2 Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) is another method of post-combustion control. Similar to SCR, the SNCR process involves the injection of a nitrogen-based reducing agent (reagent) such as ammonia (NH_3) or urea to reduce the NO_x in the flue gas to N_2 and H_2O. However, the SNCR process works without the use of a catalyst. Instead, the SNCR process occurs within a combustion unit, which acts as the reaction chamber. The heat from the boiler combustion process provides the energy for the NO_x reduction reaction. Flue gas temperatures in the range of 1,500 to 1,900 °F, along with adequate reaction time within this temperature range, are required for this technology. SNCR is currently being used for NO_x emission control on some utility boilers, and can achieve NO_x reduction efficiencies of up to 75%. However, in typical industrial applications SNCR provides 30% to 50% NO_x reduction.

2.4.1.3 Combustion Controls

Combustion controls such as flue gas recirculation (FGR), reducing air preheat temperature (RAP), oxygen trim (OT), low excess air (LEA), over-fire air (OFA), staged combustion air (SCA), and low NO_x burners (LNB), can be used to reduce NO_x emissions depending on the type of boiler, characteristics of fuel and method of firing. In practice, combustion controls have not provided the same degree of NO_x controls as provided by add-on post combustion control technologies, but are generally used in conjunction with add-on controls, such as SNCR, to increase the NO_x removal efficiency. The EGF boilers are currently equipped with modern OFA control systems.

As indicated previously, both boilers were modified in 2013 to install new OFA systems to control carbon monoxide (CO) and NO_x emissions in advance of the forthcoming 40 CFR 63, Subpart DDDDD, industrial boiler national emission standards. The modifications included upgrades to the underthrow feed systems to better distribute fuel and provide for consistent grate temperature and fuel management, installation of new overfire air supply fans and overfire air ducts and injection systems. Additionally, the boilers are equipped with automated oxygen trim systems to manage the combustion process. As a result of these modifications, CO and NO_x emissions have been optimized and represent the state-of-the-art with regard to available combustion management for the design/style of the boilers. Therefore, combustion controls is considered the base emission case for the four factor analysis.

2.4.2 NO_x Control Technology Effectiveness

Effectiveness is measured by the amount of NO_x removed by each control technology based on a comparison of the controlled emission rates to the baseline emission rates of the boilers. Table 4 provides a summary of the NO_x control technology effectiveness.

Table 4 – NO_x Control Technology Effectiveness.

Control Technology	Percent NO_x Reduction	Emission Rate (lb/MMBtu)	Tons NO_x Removed[a] (tpy)
Baseline/OFA	0	0.34	NA
SCR	80	0.07	245
SNCR	30	0.24	66

[a]Tons of NO_x removed from CCM SCR and SNCR spreadsheet.

The lower control efficiencies of 80% and 30% anticipated for the SCR and SNCR systems, respectively, are based on the fact the EGF boilers are equipped with modern OFA control systems that work to reduce the starting NO_x concentration. Furthermore, the boilers have a smaller than typical furnace size for the type of coal combusted and flue gas flow rates that are higher than typical. This operational characteristic, when combined with frequent process load swings resulting from varying production demands, results in variable flue gas temperature ranges within the boiler furnace and presents difficulties with balancing reagent injection and maintaining consistent control.

2.4.3 Evaluation of Impacts

The following sections present a detailed evaluation of the impacts of employing the feasible control technologies to control NO_x emissions from the EGF boilers. The four factors assessed include: cost of compliance, energy, non-air quality environmental impacts and remaining useful life.

2.4.3.1 Cost of Compliance

Table 5 summarizes the capital and annual operating costs associated with retrofitting NO_x control systems to each EGF boiler. The costs were obtained from the CCM SCR and SNCR spreadsheets. Detailed cost estimates indicating data sources for each cost category have been included in Appendix A.

Table 5 – NO_x Cost of Compliance (per boiler).

Description	**Technology Option**	
	SCR	**SNCR**
Emission Rate (lb/MMBtu)	0.07	0.24
Emission Reduction (tpy)	245	66
Capital Cost ($)	28,827,447	5,825,675
Total Annualized Cost ($)	2,620,761	585,550
Cost Effectiveness, per Boiler ($/ton)	10,718	8,905

2.4.3.2 Energy Impact

The application of SCR and SNCR systems would result in energy penalties in the form of electricity demand for required operation of ancillary equipment such as reagent preparation and delivery, as well as additional backpressure on the exhaust system that results in decreased operational efficiency.

2.4.3.3 Non-Air Quality Environmental Impacts

SCR and SNCR both require some form of ammonia (NH_3) source for operation. This can be stored in liquid, solid or gas, and processed on site for use. Depending on quantities stored, risk management requirements may apply. Both system are also prone to NH_3 slip from unreacted NH_3. This will result in the emission of an additional pollutant.

2.4.3.4 Remaining Useful Life

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.

Appendix A

Cost Calculations

EGF Dry FGD Capital Cost Summary

Description of Cost	($)[A]	Remarks
Direct Capital Costs		
Dry FGD Equipment[B]	5,342,587	Scaled Quote
Control/Instrumentation[C]	534,300	10% of Equipment Cost
Sales Tax	320,600	6% of Equipment Cost
Freight[C]	267,100	5% of Equipment Cost
Total Equipment Cost (TEC)	**6,464,600**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	5,494,900	Based on percentage of TEC: 12% Foundation & Supports, 40% Erection, 1% Electrical Installation, 30% Piping, 1% Painting, 1% Insulation
Retrofit Cost Adjustments [D]		
Infrastructure Relocation/Demolition	245,600	Estimated by HDR
Exhaust Stack	97,300	Estimated by HDR
Retrofit Interconnection/Ductwork	324,000	Estimated by HDR
Total Direct Investment (TDI)	12,626,400	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
Contingency	193,900	3% of TEC
Engineering	646,500	10% of TEC
Construction & Field Expense	646,500	10% of TEC
Contractor Fees	646,500	10% of TEC
Start-up Assistance	64,600	1% of TEC
Performance Test	64,600	1% of TEC
Total Indirect Investment (TII)	**2,262,600**	

Total Turnkey Cost (TTC)	**14,889,000**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor, scaled for capacity and ajdusted to 2019 dollars:
Capacity scaled using $C_n=r^{0.6}C$, Chemical Engineers' Handbook, Fifth Edition.

Alstom Sept. 2006
SDA System and Pulse Jet Fabric Filter Baghouse
$43,000,000 Total
2 SDA vessels (66' dia. X 52' side height)
Support Steel, roof penthouse
3 rotary atomizers per vessel
Lime prep system - lime silos, lakers, pumps, controls
Pulse jet fabric filter, including pulse systrem, support steel, roof penthouse
2 350-hp rotary screw air compressors, 3800 gal air receiver, air dryrers, filters
No erection or installation
No piping or insulation

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

EGF Dry FGD Fabric Filter Capital Cost Summary

Description of Cost	**($)**[A]	**Remarks**
Direct Capital Costs		
Fabric Filter Equipment[B]	4,645,728	Scaled Quote
Control/Instrumentation[C]	464,600	10% of Equipment Cost
Sales Tax	278,700	6% of Equipment Cost
Freight[C]	232,300	5% of Equipment Cost
Total Equipment Cost (TEC)	**5,621,300**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	4,159,800	Based on percentage of TEC: 4% Foundation & Supports, 50% Erection, 8% Electrical Installation, 1% Piping, 4% Painting, 7% Insulation
Retrofit Cost Adjustments [D]		
Infrastructure Relocation/Demolition	-	Included in SDA Costs
Exhaust Stack	-	Included in SDA Costs
Retrofit Cost Addition	-	Included in SDA Costs
Total Direct Investment (TDI)	9,781,100	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
Contingency	168,600	3% of TEC
Engineering	562,100	10% of TEC
Construction & Field Expense	1,124,300	20% of TEC
Contractor Fees	562,100	10% of TEC
Start-up Assistance	56,200	1% of TEC
Performance Test	56,200	1% of TEC
Total Indirect Investment (TII)	**2,529,500**	

Total Turnkey Cost (TTC)	**12,310,600**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor, scaled for capacity and ajdusted to 2019 dollars:
Capacity scaled using $C_n=r^{0.6}C$, Chemical Engineers' Handbook, Fifth Edition.

Alstom Sept. 2006
SDA System and Pulse Jet Fabric Filter Baghouse
$43,000,000 Total
2 SDA vessels (66' dia. X 52' side height)
Support Steel, roof penthouse
3 rotary atomizers per vessel
Lime prep system - lime silos, lakers, pumps, controls
Pulse jet fabric filter, including pulse systrem, support steel, roof penthouse
2 350-hp rotary screw air compressors, 3800 gal air receiver, air dryrers, filters
No erection or installation
No piping or insulation

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual,
Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

EGF Dry FGD/Fabric Filter Annual Cost Summary

Description of Cost	**($)**[A]	**Remarks**
Direct Annual Costs [B]		
Dry FGD Labor	49,300	1 hr per shift, assumed 8 hr shifts
Dry FGD Supervisor	7,400	15% of labor
Fabric Filter Labor	65,700	2 hr per shift, assumed 8 hr shifts
Fabric Filter Supervisor	9,900	15% of labor
Solvent (Reagent)	457,900	Consumption x cost
Fabric Filter Bag Replacement	304,900	Labor plus bag cost
Solids Scrubber Disposal	100,300	Production x cost
Solids Fly Ash Disposal	168,000	Production x cost
Maintenance Labor, Dry FGD	49,300	1 hr per shift, assumed 8 hr shifts
Maintenance Material, Dry FGD	49,300	100% of labor
Maintenance Labor, Fabric F.	65,700	2 hr per shift, assumed 8 hr shifts
Maintenance Material, Fabric F.	65,700	100% of labor
Induced Draft Fan	231,100	Consumption x cost
Pump	76,700	Consumption x cost
Direct Annual Costs (DAC)	**1,701,200**	
Indirect Annual Costs [C]		
Overhead	675,100	60% of O&M Labor
Administrative Charges	544,000	2% of Total Capital Investment
Property Taxes	272,000	1% of Total Capital Investment
Insurance	272,000	1% of Total Capital Investment
Dry FGD Annualized Costs[D]	1,194,700	(Capital Investment) x (CFR of 0.08024)
Fabric Filter Annualized Costs[D]	987,800	(Capital Investment) x (CFR of 0.08024)
Indirect Annual Costs (IAC)	**3,945,600**	
Total Annualized Costs (TAC)	**5,646,800**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs are based on site-specific design parameters.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers and fabric filters.

[D] Capital Recovery Factor (CFR) based on 20 year life and an interst rate of 5%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

EGF Dry Sorbent Injection Capital Cost Summary

Description of Cost	**($)[A]**	**Remarks**
Direct Capital Costs		
DSI Equipment[B]	1,490,000	Vendor Quote
Control/Instrumentation[C]	149,000	10% of Equipment Cost
Sales Tax	89,400	6% of Equipment Cost
Freight[C]	74,500	5% of Equipment Cost
Total Equipment Cost (TEC)	**1,802,900**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	1,532,500	Based on percentage of TEC: 12% Foundation & Supports, 40% Erection, 1% Electrical Installation, 30% Piping, 1% Painting, 1% Insulation
Flatwork/Drainage/Retrofit[D]	52,000	Estimated HDR
Total Direct Investment (TDI)	3,387,400	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
Contingency	180,300	10% of TEC (Retrofit Adjustment, HDR)
Engineering	90,100	5% of TEC
Construction & Field Expense	180,300	10% of TEC
Contractor Fees	180,300	10% of TEC
Start-up Assistance	18,000	1% of TEC
Performance Test	36,100	2% of TEC (Adjusted, HDR)
Total Indirect Investment (TII)	**685,100**	

Total Turnkey Cost (TTC)	**4,072,500**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor.

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

[D] Estimated by HDR.

EGF Dry Sorbent Injection Annual Cost Summary

Description of Cost	($)[A]	Remarks
Direct Annual Costs [B]		
DSI Labor	24,600	1/2 hr per shift, assumed 8 hr shifts
DSI Supervisor	3,700	15% of labor
Solvent (Trona)	55,000	Consumption x cost
Solids Fly Ash Disposal	27,000	Production x cost
Maintenance Labor	24,600	1/2 hr per shift, assumed 8 hr shifts
Maintenance Material, Dry FGD	24,600	100% of labor
Induced Draft Fan/Pumps	23,000	Consumption x cost
Direct Annual Costs (DAC)	**182,500**	
Indirect Annual Costs [C]		
Overhead	79,500	60% of O&M Labor
Administrative Charges	81,500	2% of Total Capital Investment
Property Taxes	40,700	1% of Total Capital Investment
Insurance	40,700	1% of Total Capital Investment
DSI Annualized Costs[D]	334,100	(Capital Investment) x (CFR of 0.08024)
Indirect Annual Costs (IAC)	**576,500**	
Total Annualized Costs (TAC)	**759,000**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs are based on site-specific design parameters and vendor quote.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers and fabric filters.

[D] Capital Recovery Factor (CFR) based on 20 year life and an interst rate of 5%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

TCI = 1.3 x (SCR_{cost} + RPC + APHC + BPC)

Capital costs for the SCR (SCR_{cost}) =	$15,008,924	in 2019 dollars
Reagent Preparation Cost (RPC) =	$2,970,717	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2019 dollars
Balance of Plant Costs (BPC) =	$4,195,318	in 2019 dollars
Total Capital Investment (TCI) =	$28,827,447	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

SCR_{cost} = 310,000 x $(NRF)^{0.2}$ x $(B_{MW}$ x HRF x $CoalF)^{0.92}$ x ELEVF x RF

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

SCR_{cost} = 310,000 x $(NRF)^{0.2}$ x (0.1 x Q_B x $CoalF)^{0.92}$ x ELEVF x RF

SCR Capital Costs (SCR_{cost}) =	$15,008,924 in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

RPC = 564,000 x $(NOx_{in}$ x B_{MW} x NPHR x $EF)^{0.25}$ x RF

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

RPC = 564,000 x $(NOx_{in}$ x Q_B x $EF)^{0.25}$ x RF

Reagent Preparation Costs (RPC) =	$2,970,717 in 2019 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

APHC = 69,000 x $(B_{MW}$ x HRF x $CoalF)^{0.78}$ x AHF x RF

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

APHC = 69,000 x (0.1 x Q_B x $CoalF)^{0.78}$ x AHF x RF

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

BPC = 529,000 x $(B_{MW}$ x HRFx $CoalF)^{0.42}$ x ELEVF x RF

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

BPC = 529,000 x (0.1 x Q_B x $CoalF)^{0.42}$ ELEVF x RF

Balance of Plant Costs (BOP_{cost}) =	

Direct Annual Costs (DAC) =	$305,163	in 2019 dollars
Indirect Annual Costs (IDAC) =	$2,315,599	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$2,620,761	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	
Annual Catalyst Replacement Cost =		

For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.

Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x $(CC_{replace}/R_{layer})$ x FWF	* Calculation Method 1 selected.
Method 2 (for coal-fired industrial boilers):	$(Q_B/NPHR)$ x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x $(CC_{replace})$ x 35.3	
Direct Annual Cost =		

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,638 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$2,311,961 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$2,315,599 in 2019 dollars

Total Annual Cost (TAC) =	$2,620,761	per year in 2019 dollars
NOx Removed =	245	tons/year
Cost Effectiveness =	$10,718	per ton of NOx removed in 2019 dollars

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$1,794,823	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$2,686,465	in 2019 dollars
Total Capital Investment (TCI) =	$5,825,675	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$1,794,823	in 2019 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$2,686,465	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$115,709	in 2019 dollars
Indirect Annual Costs (IDAC) =	$469,841	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$585,550	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$87,385	in 2019 dollars
Annual Reagent Cost =	$q_{sol} \times Cost_{reag} \times t_{op}$ =	$23,453	in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$1,492	in 2019 dollars
Annual Water Cost =	$q_{water} \times Cost_{water} \times t_{op}$ =	$569	in 2019 dollars
Additional Fuel Cost =	$\Delta Fuel \times Cost_{fuel} \times t_{op}$ =	$2,660	in 2019 dollars
Additional Ash Cost =	$\Delta Ash \times Cost_{ash} \times t_{op} \times (1/2000)$ =	$151	in 2019 dollars
Direct Annual Cost =		$115,709	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$2,622	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$467,219	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$469,841	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$585,550	per year in 2019 dollars
NOx Removed =	66	tons/year
Cost Effectiveness =	$8,905	per ton of NOx removed in 2019 dollars

Project: Industrial Boiler DSI
Date: 8 19 2019
Estimate Basis: Conceptual
Costs: 2019$
Location: American Crystal Sugar

CONCEPTUAL CAPITAL COST ESTIMATE SUMMARY

I.	MOBILIZATION AND SITE PREPARATION	$40,000
II.	SITE IMPROVEMENTS	$41,000
III.	DRY SORBENT INJECTION EQUIPMENT	$1,865,000
IV.	ELECTRICAL MODS	$373,000
	SUBTOTAL CONSTRUCTION	$2,320,000
	DESIGN/ENGINEERING	$140,000
	PERFORMANCE TESTING	$100,000
	START-UP AND COMMISSIONING	$96,000
	CONTINGENCY (20%)	$460,000
	TOTAL CAPITAL COST	$3,120,000

I. MOBILIZATION AND SITE PREPARATION

Item	Quantity	Units	Unit Price	Item Cost	Total
Geotechnical Services	1	LS	$10,000	$10,000	
Surveying	1	LS	$5,000	$5,000	
Construction Offices	1	LS	$10,000	$10,000	
Mobilization	1	LS	$10,000	$10,000	
Temporary Power	1	LS	$5,000	$5,000	
Const. Access, Parking and Laydowr	1	LS	$0	$0	
Temporary Fencing	0	lf	$15	$0	
Subtotal I					$40,000

II. SITE IMPROVEMENTS

Item	Quantity	Units	Unit Price	Item Cost	Total
Earthwork					
General Earthwork	89	cy	$7	$1,000	
Finishing Grading	89	sy	$1.00	$0	
Roadways	0	sy	$60	$0	
Asphalt Pavement	0	sy	$60	$0	
Fire Protection	1	LS	$10,000	$10,000	
Water Supply	1	LS	$5,000	$5,000	
Drains and Sumps	1	LS	$20,000	$20,000	
Storm Water System	1	LS	$5,000	$5,000	
Yard Lighting	1	LS	$0	$0	
Subtotal II					$41,000

Notes:

IV. DRY SORBENT INJECTION EQUIPMENT

Item	Quantity	Units	Unit Price	Item Cost	Total
Foundations	1	LS	$25,000	$25,000	
DSI Equipment	1	LS	$865,000	$865,000	
Erection	1	LS	$300,000	$300,000	
Viper Mills	1	LS	$475,000	$475,000	
Dehimidifiers and Condensers	1	LS	$150,000	$150,000	
Piping	1	LS	$50,000	$50,000	
Subtotal IV					$1,865,000

IV. ELECTRICAL MODS

Item	Quantity	Units	Unit Price	Item Cost	Total
Allowance	1	LS	$373,000	$373,000	
Subtotal V					$373,000
Subtotal I through V					$2,320,000

SYSTEM OPERATING COST, $ US 2019

I.	LABOR	22,000
II.	REAGENTS AND SUPPLIES	55,000
III.	EQUIPMENT MAINTENANCE	23,000
IV.	ASH DISPOSAL COST	27,000
	SUBTOTAL OPERATION & MAINTENANCE	127,000
	CONTINGENCY (20%)	25,000
	TOTAL ANNUAL OPERATION & MAINTENANCE COST	152,000
	TOTAL ANNUAL LOST REVENUE	23,000
	Capacity Factor	85.1%

	Item	Qnty	Units	Unit Price	Item Cost
I.	LABOR				
	Operators	0.20			
	Required Staff	416	hr	54.00	22,000
	Maintenance	0			
	Required Staff	0	hr	70.00	0
	Subtotal				22,000
	Notes:				
II.	REAGENTS AND SUPPLIES				
	Trona	250	Tons	220	55,000
	Subtotal				55,000
III.	EQUIPMENT MAINTENANCE				
	(1% of construction subtotal cost)	1		23,200	23,200
	Subtotal				23,000
IV.	ASH DISPOSAL COST				
	Additional ash requiring disposal (1.43 lbs per lb Trona @ NSR 0.14)	1,333	Tons	20	27,000
	Subtotal				27,000
	Subtotal Costs I through IV				127,000
V.	UTILITIES				
	Electricity	186,369	kWh	0.06	11,000
	Electrical Capacity	25	kW	460	12,000
	Subtotal				23,000

SPRING CREEK MINE
QUALITY SPECIFICATIONS

QUALITY PARAMETER	TYPICAL (MEAN VALUE)	STANDARD DEVIATION	TYPICAL 95% RANGE		TYPICAL DRY VALUE	TYPICAL MOISTURE-ASH FREE VALUE
			-2 STD DEV	+2 STD DEV		
PROXIMATE						
% Moisture	25.40	0.56	24.28	26.52		
% Ash	4.12	0.33	3.46	4.78	5.52	
% Volatile	31.26	0.81	29.64	32.88	41.90	44.35
% Fixed Carbon	39.23	0.80	37.63	40.83	52.59	55.66
BTU/lb	9350	103	9132	9544	12517	13249
MAFBTU	13249	80.08	13089	13409		
Dry BTU	12517	93.71	12330	12705		
% Sulfur	0.38	0.07	0.20	0.48	0.46	0.48
ULTIMATE						
% Moisture	25.40	0.56	24.28	26.52		
% Carbon	54.14	3.28	47.58	60.70	72.57	76.82
% Hydrogen	3.80	0.23	3.34	4.26	5.09	5.39
% Nitrogen	0.71	0.09	0.53	0.89	0.95	1.01
% Chlorine	0.00	0.01	0.00	0.01	0.00	0.00
% Sulfur	0.34	0.07	0.20	0.48	0.46	0.48
% Ash	4.12	0.33	3.46	4.78		
% Oxygen	11.50	0.70	10.10	12.90	15.42	16.32
SULFUR FORMS						
Pyritic Sulfur (%)	0.05	0.03	0.00	0.11	0.07	0.07
Sulfate Sulfur (%)	0.01	0.015	0.00	0.04	0.01	0.01
Organic Sulfur (%)	0.28	0.06	0.16	0.40	0.38	0.40
Total Sulfur (%)	0.34	0.07	0.20	0.48	0.46	0.48
MINERAL ANALYSIS OF ASH						
% Silicon Dioxide (Silica, SiO_2)	32.52	2.78	26.96	38.08		
% Aluminum Oxide (Alumina, Al_2O_3)	17.69	1.09	15.51	19.87		
% Titanium Dioxide (Titania, TiO_2)	1.13	0.10	0.93	1.33		
% Iron Oxide (Ferric Oxide, Fe_2O_3)	4.76	0.47	3.82	5.70		
% Calcium Oxide (Lime, CaO)	15.36	1.41	12.54	18.18		
% Magnesium Oxide (Magnesia, MgO)	3.69	0.85	1.99	5.39		
% Potassium Oxide (K_2O)	0.63	0.14	0.35	0.91		
% Sodium Oxide (Na_2O)	8.24	1.00	6.24	10.24		
% Sulfur Trioxide (SO_3)	14.07	2.50	9.07	19.07		
% Phosphorous Pentoxide (P_2O_5)	0.35	0.06	0.23	0.47		
% Strontium Oxide (SrO)	0.37	0.22	0.00	0.81		
% Barium Oxide (BaO)	1.19	0.31	0.57	1.81		
% Undetermined	0.00	1.00	0.00	2.00		
Base/Acid Ratio	0.64	0.08	0.48	0.80		
Base Value	32.68	2.20	28.28	37.08		
Acid Value	51.34	3.00	45.34	57.34		
ASH FUSION TEMPERATURES						
Reducing (^{O}F)						
Initial	2106	37	2031	2181		
Softening (H=W)	2129	36	2056	2202		
Hemispherical (H=1/2W)	2141	39	2062	2220		
Fluid	2164	51	2062	2266		
Fluid-Initial Temp. Difference	58	40	0	138		
Oxidizing (^{O}F)						
Initial	2351	98	2156	2546		
Softening (H=W)	2366	81	2204	2528		
Hemispherical (H=1/2W)	2391	73	2245	2537		
Fluid	2423	77	2268	2578		
Fluid-Initial Temp. Difference	72	60	0	192		

SPRING CREEK MINE
QUALITY SPECIFICATIONS (Continued)

QUALITY PARAMETER	**TYPICAL**	**STANDARD**	**TYPICAL 95% RANGE**	
	(MEAN VALUE)	**DEVIATION**	**-2 STD DEV**	**+2 STD DEV**
ADDITIONAL ANALYSES AND CALCULATED VALUES				
T250 Temperature (^{O}F)	2153	91.88	1969	2337
HGI (at as-received moisture)	60.6	5.6	49	72
HGI % Moisture	24.13	3.88	16	32
Critical Viscosity Temperature (^{O}F)	0	0	0	0
Critical Viscosity (Poises)	0	0	0	0
% Equilibrium Moisture	23.93	0.56	22.81	25.05
Specific Gravity	1.10	0.015	1.07	1.13
%Alkalies NA2O Dry (Total Alkali Content on Coal)	0.478	0.070	0.34	0.62
%Water Soluble Alk - Na2O	0.000	0.000	0.00	0.00
%Water Soluble Alk - K2O	0.000	0.000	0.00	0.00
%Na2O - Dry Coal	0.46	0.03	0.40	0.52
%Na2O As-received Coal	0.34	0.02	0.30	0.38
Silica Value (Silica Ratio)	57.73			
Slag Factor	0.28	0.14	0.00	0.56
Slag factor per Fusion Temperature	2163	85	1993	2333
Dolomite Ratio	58.29	3.25	51.79	64.79
Ash Precipitation Index	3.97	10.1	0.00	24.17
Silica to Alumina Ratio	1.84	0.14	1.56	2.12
Calcium to Silica Ratio	0.47	0.34	0.00	1.15
Iron to Calcium Ratio	0.31	0.07	0.17	0.45
Fouling Factor (Fouling Index)	5.25	1.41	2.43	8.07
SO2/MMBTU	0.80	0.075	0.58	0.88
lbs S/MMBTU	0.36	0.075	0.21	0.51
lbs Sodium/MMBTU	0.364	0.023	0.32	0.41
lbs Ash/MMBTU	4.41	0.5	3.41	5.41

TYPICAL COAL SIZE	2 inch		
Size Fraction	**Wt. Percent**	**Cumulative Wt. Percent**	**Wt. Percent Passing Top**
+3" RD.	0%	0%	100%
3" RD. x 2" RD.	4%	4%	100%
2" RD. x 1" RD.	20%	24%	96%
1" RD. x 1/2" RD.	28%	52%	76%
1/2" RD. x 4 M	20%	71%	48%
4 M x 60 M	13%	84%	29%
60 M x 0	16%	100%	16%

TRACE ELEMENT SUMMARY

Parts Per Million Whole Coal, Dry Basis	**TYPICAL (MEAN VALUE)**	**STANDARD DEVIATION**	**TYPICAL 95% RANGE -2 STD DEV**	**+2 STD DEV**
ANTIMONY (Sb)	n/a	n/a	n/a	n/a
ARSENIC (As)	1.50	1.00	0.00	3.50
BARIUM (Ba)	n/a	n/a	n/a	n/a
BERYLLIUM (Be)	0.21	0.08	0.06	0.36
BORON (B)	n/a	n/a	n/a	n/a
BROMIDE (Br)	n/a	n/a	n/a	n/a
CADMIUM (Cd)	0.18	0.02	0.14	0.22
CHLORINE (Cl)	9.15	3.75	1.65	16.65
CHROMIUM (Cr)	2.40	0.75	0.90	3.90
COBALT (Co)	n/a	n/a	n/a	n/a
COPPER (Cu)	n/a	n/a	n/a	n/a
FLUORINE (F)	41.90	11.00	19.90	63.90
LITHIUM (Li)	n/a	n/a	n/a	n/a
MANGANESE Mn)	16.20	7.90	0.40	32.00
MERCURY (Hg)	0.07	0.03	0.01	0.13
MOLYBDNEUM (Mo)	n/a	n/a	n/a	n/a
NICKEL (Ni)	1.53	1.00	0.00	3.53
LEAD (Pb)	2.60	1.00	0.60	4.60
SELENUIM (Se)	1.20	0.90	0.00	3.00
SILVER (Ag)	n/a	n/a	n/a	n/a
STRONTIUM (Sr)	n/a	n/a	n/a	n/a
THALLIUM (Tl)	n/a	n/a	n/a	n/a
THORIUM (Th)	n/a	n/a	n/a	n/a
TIN (Sn)	n/a	n/a	n/a	n/a
URANIUM (U)	n/a	n/a	n/a	n/a
VANADIUM (V)	n/a	n/a	n/a	n/a
ZIRCONIUM (Zr)	n/a	n/a	n/a	n/a
ZINC (Zn)	n/a	n/a	n/a	n/a

*** All negative numbers were converted to 0.00**

February 1, 2022

Hassan Bouchareb
Minnesota Pollution Control Agency
520 Lafayette Road N
St. Paul, MN 55155

Re: Updated Dry Sorbent Injection Costs for American Crystal Sugar Company Four Factor Analysis

Dear Mr. Bouchareb:

As indicated in the January 25, 2022 teleconference with the Minnesota Pollution Control Agency (MPCA), American Crystal Sugar Company (ACSC) 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 ACSC East Grand Forks (EGF) and Crookston (CRK) facilities.

The original FFA for the EGF and CRK facilities was based on the assumption that 50% sulfur dioxide control (SO_2) could be attained while retaining the use of the electrostatic precipitator (ESP) controls at each of the facilities. While a DSI system might be expected to achieve a level of SO_2 control around 70%, the lower control efficiency of 50% for EGF and CRK was based on the fact that the boilers combust very low sulfur PRB coal and have relatively high flue gas flow rates associated with their over-fire-air (OFA) combustion systems to control carbon monoxide and nitrogen oxides. Additionally, the facilities are equipped with ESP controls, and therefore do not have the added benefit of additional sorbent residence time and a sorbent filter cake, which would be provided if a fabric filter were used.

Based on information received from the DSI vendor solicited for site-specific costs estimates, the calculated sorbent injection rate needed to maintain 50% control would be in excess of 700 lb/hr for each boiler at EGF and in excess of 300 lb/hr for each boiler at CRK.

Both the EGF and CRK facility boilers are subject to 40 CFR 63, Subpart DDDDD. This rule imposes a total filterable particulate (PM) limit of 0.04 lb/MMBtu for each boiler. The equivalent lb/hr emission rate is 14.2 lb/hr for the EGF boilers and 5.5 lb/hr for the CRK boilers. A review of historical stack test data for the boilers indicates that they typically operate at about 50% of the PM limit, but occasionally, approach 80% of the limit. Therefore, allowing an adequate compliance margin for sustainable future operations would result in a small margin available for additional particulate to be added to the flue gas in the form of sorbent.

The ESPs at EGF and CRK have historically provided around 99.1% control of PM. The reason for the high performance is the fact that the facilities combust a high sodium (Na_2O) coal. The high sodium content results in a lower fly ash resistivity which improves ESP performance. The addition of sodium sorbents like sodium bicarbonate or trona to flue gas works to lower resistivity of fly ash, which can improve ESP performance in situations with high fly ash resistivity. However, because EGF and CRK already have low resistivity, the addition of a sodium sorbent may actually decrease the resistivity too much and therefore, negatively impact capture performance.

Another issue impacting the potential control efficiency of the ESPs is the fact that EGF and CRK are equipped with powdered activated carbon (PAC) injection systems to control mercury emissions. In order to avoid negatively impacting mercury control, it would be necessary to install the DSI lances downstream of the PAC lances in the flue gas train. This would reduce both the residence time and mixing potential of the sorbent in the flue gas prior to entering the ESP for removal, lowering the DSI system's SO_2 control effectiveness. Actual placement of injection lances and optimum performance would need to be evaluated with complex flow modeling prior to making final determinations on control effectiveness and feasibility.

Given the uncertainty of sorbent injection impact on fly ash resistivity, as well as the concerns with optimum injection lance placement, it is difficult to estimate the level of SO_2 control that would be experienced while also minimizing the sorbent injection rate to maintain an adequate compliance margin with the PM emission limits. Without extensive site-specific testing, it is assumed that 50% control could be maintained, but with sorbent injection rates that would allow no compliance margin for continued sustainable operation.

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.

The following table presents the updated DSI costs for EGF. The costs have been updated to incorporate the following changes:

- DSI costs have been combined for both boilers at the EGF facility based on the fact that a common sorbent silo and injection system would be shared by the two boilers. Each boiler flue gas system would have a separate injection lance arrangement.
- Each boiler would require the demolition of current ESP controls and replacement with a fabric filter baghouse.
- Baseline SO_2 emissions for the EGF boilers combined is 904 tons per year.
- The percent SO_2 reduction achieved by DSI would be 70%, which results in 633 tons per year removed.

Table 1 – EGF SO_2 Cost of Compliance

Description	**DSI**
Emission Rate (lb/MMBtu)	0.14
Emission Reduction (tpy)	633
Capital Cost ($)	36,628,400
Direct Annual Cost ($)	2,849,100
Indirect Annual Cost ($)	4,697,400
Total Annualized Cost ($)	7,546,500
Cost Effectiveness ($/ton)	11,900

The following table presents the updated DSI costs for CRK. The costs have been updated to incorporate the following changes:

- DSI costs have been combined for all three boilers at the CRK facility based on the fact that a common sorbent silo and injection system would be shared with all boilers. Each boiler flue gas system would have a separate injection lance arrangement.
- Each boiler would require the demolition of current ESP controls and replacement with a fabric filter baghouse.
- Baseline SO_2 emissions for the CRK boilers combined is 735 tons per year.
- The percent SO_2 reduction achieved by DSI would be 70%, which results in 515 tons per year removed.

Table 2 – CRK SO_2 Cost of Compliance

Description	**DSI**
Emission Rate (lb/MMBtu)	0.12
Emission Reduction (tpy)	515
Capital Cost ($)	36,208,000
Direct Annual Cost ($)	2,311,700
Indirect Annual Cost ($)	4,759,600
Total Annualized Cost ($)	7,071,300
Cost Effectiveness ($/ton)	13,700

Detailed capital and annual operating costs calculations have been attached. Given the increased costs associated with adding fabric filter controls to provide enhanced SO_2 removal and adequate compliance margin with applicable PM emission limits, the implementation of DSI controls is not cost effective.

We appreciate your consideration of this additional information. If you have questions regarding the above analysis or require additional information, please do not hesitate to contact me at (763) 278-5905, or graetz@hdrinc.com.

Sincerely,

HDR Engineering, Inc.

Gregory J. Raetz, PE
Environmental Engineer

Attachment(s): DSI Cost Estimate

EGF Dry Sorbent Injection Capital Cost Summary

Description of Cost	**($)[A]**	**Remarks**
Direct Capital Costs		
DSI Equipment[B]	1,498,000	Vendor Quote
Control/Instrumentation[C]	149,800	10% of Equipment Cost
Sales Tax	89,900	6% of Equipment Cost
Freight[C]	74,900	5% of Equipment Cost
Total Equipment Cost (TEC)	**1,812,600**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	1,540,700	Based on percentage of TEC: 12% Foundation & Supports, 40% Erection, 1% Electrical Installation, 30% Piping, 1% Painting, 1% Insulation
Total Direct Investment (TDI)	3,353,300	**TEC + TIC + Site Prep. = TDI**
Indirect Capital Cost [C]		
Contingency	181,300	10% of TEC (Retrofit Adjustment, HDR)
Engineering	181,300	10% of TEC
Construction & Field Expense	181,300	10% of TEC
CFD Modeling	70,000	Vendor Quote
Contractor Fees	181,300	10% of TEC
Start-up Assistance	18,100	1% of TEC
Performance Test	36,300	2% of TEC (Adjusted, HDR)
Total Indirect Investment (TII)	**849,600**	
Total Turnkey Cost (TTC)	**4,202,900**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor, UCC, 2021.

DSI silo
Unloading Station
Mill and Compressor
No erection or installation
No piping or insulation

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

EGF DSI Fabric Filter Capital Cost Summary

Description of Cost	**($)**[A]	**Remarks**
Direct Capital Costs		
Fabric Filter Equipment[B]	11,816,600	Scaled Quote (Two Baghouses)
Control/Instrumentation[C]	1,181,700	10% of Equipment Cost
Sales Tax	709,000	6% of Equipment Cost
Freight[C]	590,800	5% of Equipment Cost
Total Equipment Cost (TEC)	**14,298,100**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	10,580,600	Based on percentage of TEC: 4% Foundation & Supports, 50% Erection, 8% Electrical Installation, 1% Piping, 4% Painting, 7% Insulation
Demolition of ESPs[D]	200,000	Demolition and Site Prep
Stack Replacement[D]	912,700	Extend two stacks to 200'
Total Direct Investment (TDI)	25,991,400	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
Contingency	428,900	3% of TEC
Engineering	1,429,800	10% of TEC
Construction & Field Expense	2,859,600	20% of TEC
Contractor Fees	1,429,800	10% of TEC
Start-up Assistance	143,000	1% of TEC
Performance Test	143,000	1% of TEC
Total Indirect Investment (TII)	**6,434,100**	

Total Turnkey Cost (TTC)	**32,425,500**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor and scaled for capacity.
Capacity scaled using $C_n = r^{0.6}C$, Chemical Engineers' Handbook, Fifth Edition.

Hammon Research-Cottrell, 2021
Pulse Jet Fabric Filter Baghouse
120 ft exhaust stack
No erection or installation
No piping or insulation

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for fabric filters.

[D] Estimated by HDR.

EGF Dry Sorbent Injection Annual Cost Summary

Description of Cost	**($)[A]**	**Remarks**
Direct Annual Costs[B]		
DSI Labor	49,200	1/2 hr per shift, assumed 8 hr shifts
DSI Supervisor	7,400	15% of labor
Fabric Filter Labor	194,400	2 hr per shift, assumed 8 hr shifts
Fabric Filter Supervisor	29,200	15% of labor
Solvent (Trona)	1,801,200	Consumption x cost
Fabric Filter Bag Replacement	304,900	Labor plus bag cost
Solids Fly Ash Disposal	168,000	Production x cost
Maintenance Labor, Fabric F.	49,200	1/2 hr per shift, assumed 8 hr shifts
Maintenance Material, Fabric F.	49,200	100% of labor
Maintenance Labor, DSI	49,200	1/2 hr per shift, assumed 8 hr shifts
Maintenance Material, DSI	49,200	100% of labor
DSI Electric Demand	36,400	606,435 kW/yr
Fabric F. Electrical Demand	61,600	513,500 kW/yr/unit
Direct Annual Costs (DAC)	**2,849,100**	
Indirect Annual Costs[C]		
Overhead	227,200	60% of O&M Labor
Administrative Charges	732,600	2% of Total Capital Investment
Property Taxes	366,300	1% of Total Capital Investment
Insurance	366,300	1% of Total Capital Investment
DSI Annualized Costs[D]	344,800	(Capital Investment) x (CFR of 0.08024)
Fabric Filter Annualized Costs[D]	2,660,200	(Capital Investment) x (CFR of 0.08024)
Indirect Annual Costs (IAC)	**4,697,400**	
Total Annualized Costs (TAC)	**7,546,500**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs are based on site-specific design parameters and vendor quote.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers and fabric filters.

[D] Capital Recovery Factor (CFR) based on 20 year life and an interest rate of 5%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

CRK Dry Sorbent Injection Capital Cost Summary

Description of Cost	**($)[A]**	**Remarks**
Direct Capital Costs		
DSI Equipment[B]	1,832,000	Vendor Quote
Control/Instrumentation[C]	183,200	10% of Equipment Cost
Sales Tax	109,900	6% of Equipment Cost
Freight[C]	91,600	5% of Equipment Cost
Total Equipment Cost (TEC)	**2,216,700**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	1,884,200	Based on percentage of TEC: 12% Foundation & Supports, 40% Erection, 1% Electrical Installation, 30% Piping, 1% Painting, 1% Insulation
Total Direct Investment (TDI)	4,100,900	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
Contingency	221,700	10% of TEC (Retrofit Adjustment, HDR)
Engineering	221,700	10% of TEC
Construction & Field Expense	221,700	10% of TEC
CFD Modeling	105,000	Vendor Quote
Contractor Fees	221,700	10% of TEC
Start-up Assistance	22,200	1% of TEC
Performance Test	44,300	2% of TEC (Adjusted HDR)
Total Indirect Investment (TII)	**1,058,300**	

Total Turnkey Cost (TTC)	**5,159,200**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor, UCC, 2021.

DSI silo

Unloading Station

Mill and Compressor

No erection or installation

No piping or insulation

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers.

CRK DSI Fabric Filter Capital Cost Summary

Description of Cost	**($)[A]**	**Remarks**
Direct Capital Costs		
Fabric Filter Equipment[B]	11,087,100	Scaled Quote (Three Baghouses)
Control/Instrumentation[C]	1,108,700	10% of Equipment Cost
Sales Tax	665,200	6% of Equipment Cost
Freight[C]	554,400	5% of Equipment Cost
Total Equipment Cost (TEC)	**13,415,400**	
Total Installation Cost (TIC)/Balance of Plant Cost[C]	9,927,400	Based on percentage of TEC: 4% Foundation & Supports, 50% Erection, 8% Electrical Installation, 1% Piping, 4% Painting, 7% Insulation
Demolition of ESPs[D]	300,000	Demolition and Site Prep
Stack Replacement[D]	1,369,000	Extend three stacks to 200'
Total Direct Investment (TDI)	25,011,800	**TEC + TIC + Site Prep. = TDI**

Indirect Capital Cost [C]		
Contingency	402,500	3% of TEC
Engineering	1,341,500	10% of TEC
Construction & Field Expense	2,683,100	20% of TEC
Contractor Fees	1,341,500	10% of TEC
Start-up Assistance	134,200	1% of TEC
Performance Test	134,200	1% of TEC
Total Indirect Investment (TII)	**6,037,000**	

Total Turnkey Cost (TTC)	**31,048,800**	**TDI + TII = TTC**

[A] Values rounded to the nearest $100.

[B] Capital equipment cost provided by vendor and scaled for capacity.
Capacity scaled using $C_n=r^{0.6}C$, Chemical Engineers' Handbook, Fifth Edition.

Hammon Research-Cottrell, 2021
Pulse Jet Fabric Filter Baghouse
120 ft exhaust stack
No erection or installation
No piping or insulation

[C] Direct and indirect cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for fabric filters.

[D] Estimated by HDR.

CRK Dry Sorbent Injection Annual Cost Summary

Description of Cost	($)[A]	Remarks
Direct Annual Costs [B]		
DSI Labor	73,800	1/2 hr per shift, assumed 8 hr shifts
DSI Supervisor	11,100	15% of labor
Fabric Filter Labor	291,600	2 hr per shift, assumed 8 hr shifts
Fabric Filter Supervisor	43,700	15% of labor
Solvent (Trona)	1,227,600	Consumption x cost
Fabric Filter Bag Replacement	143,600	Labor plus bag cost
Solids Fly Ash Disposal	115,300	Production x cost
Maintenance Labor, Fabric F.	73,800	1/2 hr per shift, assumed 8 hr shifts
Maintenance Material, Fabric F.	73,800	100% of labor
Maintenance Labor, DSI	73,800	1/2 hr per shift, assumed 8 hr shifts
Maintenance Material, DSI	73,800	100% of labor
DSI Electric Demand	47,100	785,185 kW/yr
Fabric F. Electrical Demand	62,700	348,400 kW/yr/unit
Direct Annual Costs (DAC)	**2,311,700**	

Indirect Annual Costs [C]		
Overhead	340,700	60% of O&M Labor
Administrative Charges	724,200	2% of Total Capital Investment
Property Taxes	362,100	1% of Total Capital Investment
Insurance	362,100	1% of Total Capital Investment
DSI Annualized Costs[D]	423,300	(Capital Investment) x (CFR of 0.08024)
Fabric Filter Annualized Costs[D]	2,547,200	(Capital Investment) x (CFR of 0.08024)
Indirect Annual Costs (IAC)	**4,759,600**	

Total Annualized Costs (TAC)	**7,071,300**	**DAC + IAC = TAC**

[A] Values rounded to the nearest $100.

[B] Direct annual costs are based on site-specific design parameters and vendor quote.

[C] Indirect annual cost percentages obtained from EPA's Air Pollution Control Manual, Sixth Edition, January 2002, for gas absorbers and fabric filters.

[D] Capital Recovery Factor (CFR) based on 20 year life and an interest rate of 5%, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002.

February 21, 2022

Hassan Bouchareb
Minnesota Pollution Control Agency
520 Lafayette Road N
St. Paul, MN 55155

Re: Updated Selective Non-Catalytic Reduction Performance Data for American Crystal Sugar Company Four Factor Analysis

Dear Mr. Bouchareb:

As indicated in the February 15, 2022 teleconference with the Minnesota Pollution Control Agency (MPCA), American Crystal Sugar Company (ACSC) obtained site-specific vendor quotes for Selective Non-Catalytic Reduction (SNCR) equipment in order to verify estimated capital equipment and annual operating costs, as well as the technical feasibility and potential nitrogen oxide (NO_x) control levels achievable for the ACSC East Grand Forks (EGF) and Crookston (CRK) facilities.

The original Four Factor Analysis (FFA) for the EGF and CRK facilities was based on the assumption that 30% NO_x control could be consistently attained by all boilers under all load conditions. Capital equipment and annual operating costs were estimated using the Air Pollution Control Cost Estimation Spreadsheet For Selective Non-Catalytic Reduction, as provided by the U.S. Environmental Protection Agency (EPA) Air Economics Group, Office of Air Quality Planning and Standards, June 2019. Since the previous FFA submittal, the EPA calculation spreadsheet has been revised. Additionally, site-specific information received by the SNCR equipment vendor has provided information relative to achievable NO_x control and the technical feasibility of implementing SNCR at the ACSC facilities. Therefore, the following supplemental information has been provided for your consideration regarding the implementation of NO_x control technologies.

As stated previously, the original FFA for EGF and CRK assumed a SCNR NO_x control effectiveness of 30%. This relatively low value was based on the fact that the EGF and CRK boilers are equipped with over-fire-air (OFA) combustion control systems that work to reduce the starting NO_x concentration, and the fact that the boilers have higher than typical flue gas flow rates as a result of small furnace sizes and increased air flow from the OFA systems. The high flue gas flow rates result in reduced residence times for the chemical reaction of the SNCR system to reduce NO_x formation.

The coal-fired boilers at both the EGF and CRK facilities are subject to 40 CFR 63, Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. This rule contained a requirement for each boiler to meet a carbon monoxide (CO) emission limit of 160 ppm by January 31, 2016. In order to meet the required CO emission limit it was necessary to modify and upgrade the limited

OFA systems of all of the boilers at the EGF and CRK facilities. ACSC contracted with Detroit Stoker Company to design and install advanced OFA systems in 2013 at EGF and 2014 at CRK.

In summary the projects consisted of replacing the coal feeder/distribution systems for each boiler with Detroit® Underthrow Fuel Distributors and upgrading the OFA systems to increase the level of available OFA by installing additional air injection ports and increasing the OFA fan capacity. The fuel distributors use a combination of pneumatic assistance with underthrow rotor mechanisms to provide a uniform distribution and trajectory of fuel that is continuously introduced into the combustion chamber at varying rates to follow load demands. The combination of these two project elements provided the following benefits:

- More consistent distribution of fuels with inconsistent size and moisture content;
- Improved distribution of coals with large amounts of fines;
- Increased combustion efficiency;
- Less suspension firing resulting in reduced loss on ignition; and,
- Reduced NO_x emissions by introduction of fuel lower in the burning zone of the furnace.

The capital investment for the OFA and coal feeder projects was $5,900,000 for EGF and $7,800,000 for CRK. The baseline NO_x emissions for EGF prior to project implementation was 0.46 lb/MMBtu for Boiler No. 1 and 0.49 MMBtu for Boiler No. 2. The baseline NO_x emissions for CRK prior to implementation was 0.51 lb/MMBtu for Boiler No. 1, 0.55 lb/MMBtu for Boiler No. 2, and 0.70 lb/MMBtu for Boiler No. 3.

As indicated in the FFA submitted for EGF and CRK current NO_x emission levels average 0.34 lb/MMBtu for the EGF boilers and 0.33 lb/MMBtu for the CRK boilers. The emissions data indicates an average 28% reduction of NO_x for EGF and an average 44% reduction in NO_x for CRK.

To evaluate further NO_x reduction at EGF and CRK, operating data was submitted to the SNCR vendor, FuelTech, to obtain site-specific information regarding the application of additional NO_x control. While the actual quote received is marked Confidential from the vendor, the following notable information can be shared:

- SNCR NO_x reduction performance for each boiler varies between units and operating load conditions, even for identical boiler units.
- Baseline testing and computational fluid dynamic (CFD) modeling would be required to establish more accurate actual furnace conditions and allow NO_x performance guarantees.
- The two key parameters that affect process performance and NO_x control are flue gas temperature and reagent distribution.
- The NO_x reducing reaction is temperature sensitive and typically occurs between 1600°F and 2200°F.
- Reagent must be distributed within the optimum temperature range with sufficient residence time to achieve the best performance and minimize ammonia slip.

- CRK Boiler 3 has a calculated process temperature of 2200°F, which indicates the unit is too hot for lower zone injection ports, thus limiting the injection zone to one single zone. As a result of this limitation, expected NO_x reduction is 10%.
- If CRK Boiler 3 operates at reduced load and baseline NO_x does not exceed 0.35 lb/MMBtu, 30% NO_x reduction may be achievable.
- EGF Boiler Nos. 1 and 2 have calculated process temperatures of 2280°F and 2400°F, which exceeds the optimum range. Based on boiler dimensions, there may be room for the flue gas to cool somewhat, however, at maximum load the anticipated NO_x reduction is estimated at 10 to 15% for each boiler, respectively.

Given the above limitations, it is not possible to definitively conclude that the ACSC boilers could achieve more than a 10% NO_x reduction utilizing SCNR. In order to provide a reasonable performance guarantee, significant additional boiler-specific testing and CFD modeling would be required. Furthermore, under normal operation, ACSC boilers are subject to frequent load swings to match the sugar production evaporator demands. The load swings result in combustion temperature and flow rate changes that would be difficult to balance with a SNCR system that may result in additional ammonia slip.

Additional ammonia slip may have a negative impact on mercury emissions which are currently controlled utilizing powdered activated carbon (PAC) injection. Ammonia has been demonstrated to prevent the oxidation of elemental mercury in flue gases. Given that the PAC adsorbs oxidized mercury, the introduction of excess ammonia may decrease the level of mercury control currently achieved.

The cost effectiveness for SNCR was recalculated incorporating the above-described achievable NO_x control levels utilizing the revised March of 2021 EPA Air Pollution Control Cost Estimation Spreadsheet for the EGF and CRK boilers. The following table provides a summary of the SNCR control technology effectiveness.

Table 1. SNCR Cost Effectiveness.

EGF Boiler Nos. 1 & 2	
Base Line Emission Rate	0.34 lb/MMBtu
Controlled Emission Rate	0.31 lb/MMBtu
Emission Reduction (%)	10
Emission Reduction (tpy)	29
Total Annualized Cost ($)	$491,728
Cost Effectiveness, per Boiler ($/ton)	$17,008
CRK Boiler Nos. 1 & 2	
Base Line Emission Rate	0.33 lb/MMBtu
Controlled Emission Rate	0.25 lb/MMBtu
Emission Reduction (%)[A]	25%
Emission Reduction (tpy)	28
Total Annualized Cost ($)	$332,596
Cost Effectiveness, per Boiler ($/ton)	$11,929

CRK Boiler No. 3	
Base Line Emission Rate	0.32 lb/MMBtu
Controlled Emission Rate	0.29 lb/MMBtu
Emission Reduction (%)	10%
Emission Reduction (tpy)	13
Total Annualized Cost ($)	$340,902
Cost Effectiveness, per Boiler ($/ton)	$25,379

[A] The achievable level of NO_x control for Boiler Nos. 1 &2 was reduced from 30% to 25% based on the lower end of the effective temperature range and the reduced residence time and boiler operational characteristics.

In consideration of the significant capital investment already made by ACSC to upgrade the boiler combustion systems and thereby reduce NO_x emissions, the additional incremental control provided by the addition of SNCR systems is deemed cost prohibitive for the additional level of NO_x reduction that would be achieved. Furthermore, ammonia slip emissions from an SNCR system would have the potential to negatively impact existing mercury control, as well as contribute to ammonium sulfate particle emissions that would likely offset any small visibility benefit gained by NO_x reduction.

It is proposed that the existing recently upgraded OFA and fuel feed systems on the EGF and CRK boilers be considered as effective emission controls and provide reasonable justification for no additional NO_x control. This is consistent with the August 20, 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period issued by the EPA.

We appreciate your consideration of this additional information. If you have questions regarding the above analysis or require additional information, please do not hesitate to contact me at (763) 278-5905, or graetz@hdrinc.com.

Sincerely,

HDR Engineering, Inc.

Gregory J. Raetz, PE
Environmental Engineer

Attachment(s): Revised SNCR Control Cost Spreadsheets

From: Raetz, Gregory
To: Bouchareb, Hassan (MPCA)
Cc: Doug Emerson
Subject: American Crystal Regional Haze Supplemental Info
Date: Tuesday, March 8, 2022 5:48:55 PM
Attachments: American Crystal Sugar SNCR Redacted 03 08 22.pdf

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Hassan,

I have attached a redacted version of the vendor quote for SNCR systems. I spoke with the vendor and they were unwilling to share the cost information as it would put them at a competitive disadvantage, however, they were willing to share the performance information.

Couple things to note:

1. The capital equipment costs were fairly close to the calculated costs using the spreadsheet, so I don't think there are any concerns there. Using the spreadsheet should allow us to provide an EPA accepted approach to cost estimation.
2. The performance data discussed in the quote generally shows two ranges of control, one for max operations and one for reduced load. It is the max operations that we need to be concerned with because we routinely hit high levels during production.
3. The information provided by the vendor was for a budgetary cost estimate and predicted control levels. In the event that a firm contract and performance guarantees were sought, both the price would go up and the guaranteed performance (control) would likely go down. Therefore, I believe we are providing a conservative assessment.

Let me know if you have any questions.

Greg

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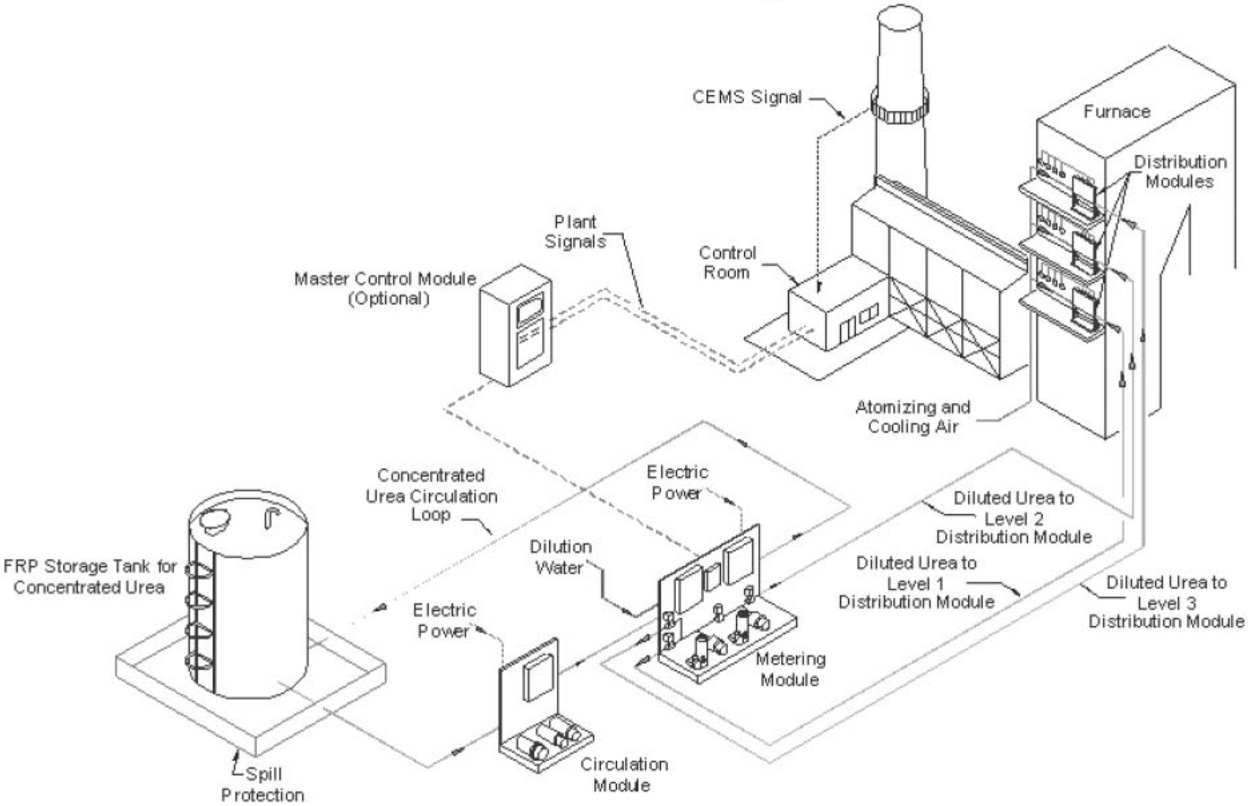
FUEL TECH®
Technologies to enable clean efficient energy

United Conveyor Corporation
HDR Specification 10304686-0ZP-M100
DSI and SNCR Request for Information

American Crystal Sugar Company
Crookston and East Grand Forks, MN
NOxOUT SNCR Systems



Fuel Tech Proposal 21-B-046, Rev 0

September 16, 2021

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1.0 EXECUTIVE SUMMARY

In accordance with the above referenced HDR Specification and Request for Information from DSI and SNCR suppliers, Fuel Tech, Inc. (FTI) is pleased to submit our final budgetary proposal covering the supply of NOxOUT® SNCR systems for three (3) B&W coal-fired boilers at the ACSC plant in Crookston, MN, and two (2) B&W coal-fired boilers at their plant in East Grand Forks, MN. For the purposes of this initial RFI, Fuel Tech is supporting United Conveyor Corporation who would be supplying the DSI and SNCR systems as a package.

In support of UCC's effort, FTI has included the following in our proposal:

- SNCR NOx reduction performance for each boiler, which varies between units and operating load conditions – even for "identical" units,
- A breakdown of the SNCR systems Scope of Supply for each plant site indicating the
  - Common Equipment such as the urea storage tank and circulation/pumping system that will supply concentrated urea to each unit, and
  - Metering, Distribution, and Injection equipment required for each boiler.
- Baseline Testing and CFD/CKM Modeling that will be required to establish the actual furnace conditions such as furnace exit gas temperature, CO, O2, and NOx concentration, which are then used in conjunction with the provided boiler drawings to locate the injectors and provide NOx reduction performance guarantees, and
- Other Field Services such as startup and optimization of each SNCR system, as well as in-class and hands-on operator training.

This proposal incorporates the information sent with our previous transmittals that did not provide a complete package in response to the RFI.

The SNCR Process Design Tables are included in Section 5, followed by the Supply of Supply and Scope of Supply by Others in Section 6. The quality specifications that pertain to the quality of water used for dilution of the 50% urea and the corresponding quality requirements that may be sued for sourcing 50% urea, are included in Section 7.

A preliminary, typical Project Schedule and the CRK and EGF SNCR system pricing are provided in Section 8 and 9, respectively, followed by our standard Terms and Conditions, Exhibit C-3 and Exhibit C-1 Fuel Tech Service Pricing Schedule in Section 10. Marketing brochures and our Approved Vendor List may be found in Section 11, Supporting Documentation.

2.0 FUEL TECH CORPORATE PROFILE

(NASDAQ: FTEK) Fuel Tech is a leading technology company engaged in the worldwide development, commercialization, and application of state-of-the-art proprietary technologies for air pollution control, process optimization, combustion efficiency, and advanced engineering services. These technologies enable customers to operate efficiently in a cost-effective and environmentally sustainable manner.

Fuel Tech operates as a fully integrated company with a capital projects business to leverage its Air Pollution Control (APC) technologies, and a specialty chemicals business which builds upon its proprietary FUEL CHEM® processes. Both segments rely heavily on the Company's unique ability to inject chemicals in combustion units, in precise concentrations and locations, to achieve a desired outcome.

Incorporated in 1987, Fuel Tech has approximately 90 employees with more than 20% of its full-time staff holding advanced degrees. The Company maintains Corporate Headquarters in Warrenville, Illinois with additional domestic offices in Durham, North Carolina and Stamford, Connecticut, and an international office are located in Milan, Italy.

The Company's post-combustion, in-furnace nitrogen oxide (NOx) reduction technologies include NOxOUT® and HERT™ Selective Non-Catalytic Reduction (SNCR), Advanced SNCR, and Rich Reagent Injection systems. Fuel Tech also designs and supplies Selective Catalytic Reduction (SCR) systems that rely on either ammonia or aqueous urea reagents. In addition, for projects in which the emission target and or retrofit costs don't justify the application of standalone SCR, Fuel Tech can supply hybrid SNCR and SCR systems. Finally, for SCR system installations that require a safe reagent, our ULTRA® systems thermally decompose liquid urea to generate ammonia on-site, on an as-needed basis.

Through a 2014 acquisition, Fuel Tech added flue gas conditioning (FGC) and electrostatic precipitator rebuild and upgrade capabilities to assist our clients with tighter particulate matter emission limits, while dealing with the increased mass flow associated with the addition of sulfur and mercury capture sorbents.

Fuel Tech's experience base covers more than 1,200 installations on a wide range of combustion units firing various fuels and fuel combinations, including approximately 700 SNCR systems, 80 SCR systems, 290 ULTRA systems, and nearly 120 ESP rebuilds and FGC systems.

Many of Fuel Tech's products and services rely heavily on the Company's exceptional Computational Fluid Dynamics modeling capabilities, which are enhanced by internally developed, high-end visualization software. These capabilities, coupled with the Company's innovative technologies and multi-disciplined team approach, enable Fuel Tech to provide practical solutions to some of our customers' most challenging problems.

3.0 SNCR PROCESS DESIGN

The SNCR Process is a post-combustion NOx reduction method that reduces NOx through the controlled injection of reagent into the post-combustion flue gas path. The reagent recommended for this application is a 50% aqueous urea solution, which would be diluted with water having an appropriate quality prior to injection. Depending on the water quality, a stabilized urea formulation may be recommended to deal with potential issues associated with total water hardness. Whether or not stabilized urea is required, it is readily available from any of our licensed urea suppliers – or others that meet the quality requirements provided – and requires no special safety precautions for handling. Specifically, the chemical makeup of the reagent will not trigger any of the site requirements covered by OSHA standards 1910.119 and 1910.120.

The use of urea for control of oxides of nitrogen was developed under the sponsorship of the Electric Power Research Institute (EPRI) between 1976 and 1981. Fuel Tech once held the exclusive license from EPRI covering the commercialization and advancement of this NOx reduction technology. These early investigations provided fundamental thermodynamic and kinetic information for the NOx-urea reaction chemistry and identified minimal traces of reaction by-products. The predominant reaction is described by:

$$\mathrm{NH2CONH2 + 2NO + \tfrac{1}{2}\,O2 \Rightarrow 2N2 + CO2 + 2H2O}$$

Urea + Nitrogen Oxide + Oxygen ⇨ Nitrogen + Carbon Dioxide + Water

Through some trace quantities of ammonia and carbon monoxide may form, the level of by-products produced can be minimized through proper application of the process.

The NOx removal efficiency and reagent utilization are related by a variable known as the Normalized Stoichiometric Ratio (NSR). This ratio is defined as shown below. The reagent utilization is equal to the NOx reduction divided by the NSR.

$$\text{NSR} = \frac{\text{Actual Molar Ratio of Urea to Baseline NOx}}{\text{Theoretical Ratio to Reduce One Mole of NOx}}$$

Fuel Tech has advanced the original, licensed technology by developing and refining chemical injection hardware, widening the applicable temperature range, and gaining process control expertise as a result of many commercial applications.

The SNCR Process is designed with the aid of computational fluid dynamics (CFD) and our chemical kinetic model (CKM). The CFD model simulates flue gas flows and temperature inside the furnace while the CKM calculates the reaction between urea and NOx based on temperature and flow information from the CFD model. A combination of these two models determines the optimum temperature region and the injection strategy required to effectively distribute the reagent. Recent technology advancements enable Fuel Tech to apply 3D visualization techniques to evaluate rapidly changing operating conditions and their impact on the SNCR process in real time.

Chemical injectors developed by Fuel Tech facilitate the reagent distribution. These injectors use compressed air to atomize and specially designed tips to direct the diluted urea into the post-combustion gas path. The droplet size distribution produced by these injectors promotes efficient contact between the decomposed urea reagent and the NOx molecules in the flue gas.

Two key parameters that affect the process performance are flue gas temperature and reagent distribution. The NOx reducing reaction is temperature sensitive, typically occurring between 1600°F and 2200°F. By-product emissions (NH3 slip) may become significant at the lower end of this range while chemical utilization and NOx reduction decrease at the higher end of the temperature range. It is important to note that this optimum temperature range is specific to each application. The reagent must be distributed within this optimum temperature zone to achieve the best performance.

The figure below helps illustrate the NOx reduction versus temperature challenge that SNCR faces. If it were possible to release the chemical (after injection and droplet evaporation) at a nominal temperature of 1800°F and provide sufficient residence time for the reactions, NOx reduction via SNCR can be a very efficient process.

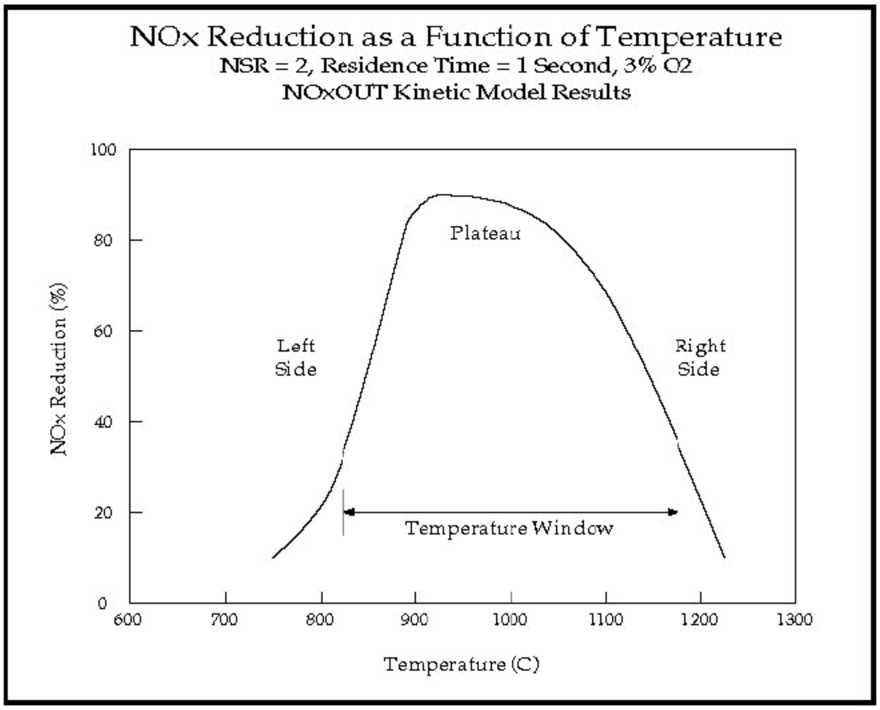

Figure 1 – NOx Reduction as a Function of Temperature

The SNCR Process is designed with the aid of in-house Computational Fluid Dynamics (CFD) and a proprietary Chemical Kinetic Model (CKM) subroutine. The CFD model simulates flue gas flows and temperature in the upper furnace while the CKM calculates the reaction between urea and NOx based on temperature and flow information provided by the CFD model. A combination of these two models determines the optimum temperature region and the injection strategy required to effectively distribute the reagent and reduce NOx. Recent technology advancements enable Fuel Tech to apply 3D visualization techniques to evaluate rapidly changing operating conditions and their impact on the SNCR process in real time.

In the back block of the NOxOUT injector body, water encapsulated, air atomized droplets are formed and are then directed into the flue gas flow. The injector tip shapes the flow and the droplet momentum carries the reagent into the convection pass where the urea decomposes and eventually reacts with the NOx molecules. The final spray characteristics and flow rate of diluted reagent for each injector are fine-tuned during system optimization and startup to correspond to each unit's boiler operating loads, fuel combinations, and uncontrolled NOx concentrations.

Using a feed forward signal such as unit steam flow, the NOx emission rate signal from the CEMS or a NOx process control monitor as feedback, and the system settings established during the optimization process, the SNCR system runs in the background under the control of an on-board Allen-Bradley CompactLogix PLC (Ethernet or optional ControlNet or DeviceNet) and is transparent to the other plant operations. The SNCR system information will be available to the unit operators on an optional control room computer display or can be tied directly into the plant Distributive Control System if one is available.

DCS control and ControlLogix processor options are available, if required.

4.0 CFD and CKM MODELING

4.1 Computational Fluid Dynamics Modeling (CFD)

Fuel Tech creates computer models of our clients' units as part of our engineering design process. A technique known as Computational Fluid Dynamics (CFD) is used to estimate the flue gas properties locally within the unit, and subsequently to assist in the determination of appropriate injector locations and characteristics for proper NOx control. Once constructed, the computer model can be modified to estimate the effects of changes in operating conditions.

The model contains many cells which closely approximate the geometry of the Client's unit. Each cell is associated with a set of coefficients describing the flue gas properties therein. Some of these properties are temperature, density, velocity, and composition. Certain cells are identified as mass or energy sources, others as places where mass or energy leave the system. Mass, energy, and momentum balances are repetitively performed on all cells until the coefficients no longer change between iterations (i.e., the solution is "converged"). The converged results are then displayed using a post-processing program.

In a typical SNCR project, the unit is modeled without urea injection to determine the temperature and flow behavior. Once an appropriate temperature regime is identified, a model simulating injection is performed. Injector characteristics are adjusted to provide the best chemical distribution subject to the intrinsic constraints for that unit. This process is repeated for each set of operating conditions. Final model refinement is performed as an engineering service at the time of the SNCR system installation.

Input data describing the physical unit and its operations are supplied by the Client. These data must be sufficient to establish the unit structure and all mass and energy inputs (or outputs) to the unit for each evaluated condition. Preferably, the structural data will be provided as an annotated set of process blueprints including, but not limited to a side sectional profile, front sectional profile, and plan view (including a plan section through the convection pass heat transfer surface). Burners, secondary or other air inlet ports, flow diverters, and other features which influence the flue gas flow or distribution should be clearly indicated. Refractory lining, tube spacing, and other factors influencing heat transfer should also be shown.

Operational data must include the mass flow rate and temperature of each mass source for the unit (fuels, combustion air, flue gas recirculation, waste gas sources, etc.). The mass flow information should be on an actual rather than dry basis. The heating value, physical state, and composition (including moisture) are required for the fuel. If specific information is not available, for instance as is often the case for primary/secondary air distribution, the Client is requested to provide his or her best estimate of that value.

Additional process information may be requested by Fuel Tech if required to properly complete the model.

Actual field data should be provided when available. These data provide a basis for the interpretation of model results and decreases design uncertainty. The field data also allow the model to be fine-tuned to the Client's unit in order to represent more closely the true operating conditions if the accuracy of standard estimates is insufficient.

The final results represent, in the opinion of Fuel Tech, the best available estimate of the conditions within the unit, recognizing the limitations of the model and the approximations employed.

4.2 Chemical Kinetics Model (CKM)

The chemistry of the NOxOUT® (SNCR) Process involves over ninety individual chemical reactions describing interactions among thirty-one species. To understand the effects of process parameters, an ideal chemical kinetic model was developed. This model describes an ideal plug flow, i.e., no temperature or species concentration gradient in radial direction and no back-mixing. Species concentrations with this type of flow are described by a set of ordinary differential equations. The number of equations depends on the number of species being modeled, and the equations are interrelated through reaction rates. Enthalpy equations are neglected in the model. Instead, either a measured or estimated temperature profile is a model input.

Reaction rates, density, and thermodynamic information are supplied by a library of gas-phase subroutines. This package of subroutines compiles user supplied reaction sets and a thermodynamic data file. The resulting sets of differential equations are integrated simultaneously using a numerical integrator called LSODE. The initial conditions for the calculation are the equilibrium concentrations of species at the as-measured temperature and excess O_2. Measured NOx concentration is also an input. Equilibrium concentration is calculated using a program called STANJAN developed at Stanford University.

Over the years, FTI has made improvements to the CKM and results from our modeling efforts allow FTI predict NOx reduction performance and locate the SNCR injectors in the appropriate locations to cover the applicable load range. This is a tool for the development of our injection strategy and basis for providing and meeting NOx emission guarantees.

4.3 Visualization Services

Fuel Tech's process visualization technology, derived from a collaborative effort between Fuel Tech and Argonne National Laboratory, is a new interactive computer-based system which uses virtual reality technology to provide insightful visualizations of CFD results. The virtual reality display system intuitively displays the results of process simulations and provides the user with an interactive interface to modify the inputs used in the calculations.

For instance, nozzles can be positioned and moved using a wand – a handheld interface providing many degrees of freedom in motion and input. As the nozzle is placed or moved, the spray trajectories are rapidly computed and re-displayed in the virtual environment. The interactivity and computing power of this system permits optimizations of spray configurations to be determined in minutes, rather than in days as is common using most currently available simulation applications. The gas flows inside the boiler can also be visualized in this environment using 'flying vectors'. The vectors are tetrahedral darts that follow fluid flow lines through the unit. The color of the darts can be made to represent velocity, temperature, or other quantities of interest.

4.4 Reports

Report(s) will be prepared summarizing the results of the Temperature Mapping and CFD/CKM modeling efforts will be provided for the Owner and the applicable FTI Technology.

a. The temperature mapping results will include a sketch of the furnace with temperature readings at each elevation, location, and insertion depth for each load point as well as control room operational data. Temperatures recorded at the economizer inlet/exit may also be summarized for the various load conditions.

b. The CFD/CKM modeling results will include computer printouts of the furnace temperatures and velocities at various planes within the unit, three-dimensional representation of the temperature windows as well as the effects of load changes, printouts of the reaction rates and predicted NOx reduction capability for the injection locations.

c. Optimum NOxOUT® SNCR injection strategy for FTI provided equipment will be identified.

d. Detailed commercial estimates of the performance capabilities of the SNCR Process, including the equipment configuration, expected reagent consumption, and ammonia slip will be provided.

5.0 SNCR PROCESS DESIGN TABLES

5.1 Crookston Units 1 and 2

American Crystal Sugar Company **Crookston, MN Plant (CRK)**	Units	**B&W Coal-fired Boilers**	
Design Basis		NOxOUT® SNCR	
Operating Load Range	%MCR	65 to 100%	
Fuel Fired		Spring Creek Coal	
Boiler Designation		Unit 1 Spreader Stoker	Unit 2 Spreader Stoker
Gross Heat Input	MMBtu/hr	137.0	137.0
Baseline NOx	lb/MMBtu	0.320	0.340
Baseline NOx	b/hr	43.8	46.6
Expected SNCR NOx Reduction	%	32.5%	35.0%
Target NOx	lb/MMBtu	0.216	0.221
Target NOx	b/hr	29.6	30.3
Estimated Average Process Temperature	°F	1800	1800
Assumed CO at Furnace Exit - See Note 1	ppm	< 100	< 100
Expected Urea Consumption, 50% by Weight	gph	7.8	8.9
Average NH3 Slip, As Measured at Stack	ppmd	10	10
Reagent Distribution Strategy - Boilers 1 and 2			
• Zone 2 (Upper): Four {4} Air Atomized, Standard Flow NOxOUT Injectors			
• Zone 1 (Lower): Four {4} Air Atomized, Standard Flow NOxOUT Injectors			
Process Design Comments			
Note 1: Due to the very high oxygen concentration, the CO is expected to be almost completely oxidized to CO2.			

5.2 Crookston Unit 3

American Crystal Sugar Company Crookston, MN Plant (CRK)		B&W Coal-fired Boilers	
Design Basis		NOxOUT® SNCR	
Operating Load Range	%MCR	65 to 100%	
Fuel Fired		Spring Creek Coal	
Boiler Designation		Unit 3 Sterling Boiler	Unit 3 Sterling Boiler
Gross Heat Input	MMBtu/hr	132.0	165.0
Baseline NOx	lb/MMBtu	0.350	0.350
Baseline NOx	b/hr	46.2	57.8
Expected SNCR NOx Reduction - See Note 1	%	30.0%	10.0%
Target NOx	lb/MMBtu	0.245	0.315
Target NOx	b/hr	32.3	52.0
Estimated Average Process Temperature - See Note 2	°F	2080	2200
Assumed CO at Furnace Exit - See Note 3	ppm	< 100	< 100
Expected Urea Consumption, 50% by Weight	gph	16.5	7.9
Average NH3 Slip, As Measured at Stack	ppmd	10	5
Reagent Distribution Strategy - Boiler 3			
• Zone 1: Three {3} Air Atomized, Standard Flow NOxOUT Injectors			
Process Design Comments			
Note 1: At 65% MCR, if the CRK3 baseline does not exceed 0.35 lb/MMBtu, a target NOx of 0.23 lb/MMBtu should be achievable. If the estimated CRK3 temperature is accurate, the unit is too hot for a lower zone of injection even at reduced load.			
Note 2: The SNCR process temperature has been estimated using the NHI/EPRS calculation [Net Heat Input (NHI) and Effective Projected Radiant Surface (EPRS)]. CRK3 is expected to be hotter than CRK1 and CRK2 due to its higher GHI, smaller cross section and shorter height. The NHI/EPRS calculation takes into account the boiler depth and width and the height, typically measured from the furnace floor to the horizontal plane at the tip of the bullnose.			
Note 3: Due to the very high oxygen concentration, the CO is expected to be almost completely oxidized to CO2.			

5.3 East Grand Forks Unit 1

American Crystal Sugar Company East Grand Forks, MN Plant (EGF)	Units	**B&W Coal-fired Boiler**	
Design Basis		NOxOUT® SNCR	
Fuel Fired		Spring Creek Coal	
Load Designation	NA	Typical	Maximum
Boiler Designation		Unit 1 Stoker-fired	Unit 1 Stoker-fired
Gross Heat Input	MMBtu/hr	284.8	356.0
Baseline NOx	lb/MMBtu	0.370	0.370
Baseline NOx	b/hr	105.4	131.7
Expected SNCR NOx Reduction	%	35.0%	15.0%
Target NOx	lb/MMBtu	0.241	0.315
Target NOx	b/hr	68.5	112.0
Estimated Average Process Temperature - See Note 1	°F	2280	2400
Assumed CO at Furnace Exit - See Note 2	ppm	< 100	< 100
Expected Urea Consumption, 50% by Weight	gph	34.7	57.8
Average NH3 Slip, As Measured at Stack	ppmd	10	5
Reagent Distribution Strategy - Boilers 1 and 2			
◆ Zone 1 (Lower): Eight {8} Air Atomized, Standard Flow NOxOUT Injectors			
◆ Zone 2 (Upper): Four {4} Air Atomized, Standard Flow NOxOUT Injectors			
Process Design Comments			
Note 1: The temperature has been estimated using the NHI/EPRS calculation. It is fairly high since this is a short unit and the distance between the grate and the bullnose is about 24 feet. However, there are at least another 15 feet between the bullnose and the roof which may allow the flue gas to cool down somewhat.			
Note 2: Due to the very high oxygen concentration, the CO is expected to be almost completely oxidized to CO2.			

5.4 East Grand Forks Unit 2

American Crystal Sugar Company **East Grand Forks, MN Plant (EGF)**	Units	**B&W Coal-fired Boiler**	
Design Basis		NOxOUT$^{®}$ SNCR	
Fuel Fired		Spring Creek Coal	
Load Designation	NA	Typical	Maximum
Boiler Designation		Unit 2 Stoker-fired	Unit 2 Stoker-fired
Gross Heat Input	MMBtu/hr	284.8	356.0
Baseline NOx	lb/MMBtu	0.320	0.320
Baseline NOx	b/hr	91.1	113.9
Expected SNCR NOx Reduction	%	30.0%	10.0%
Target NOx	lb/MMBtu	0.224	0.288
Target NOx	b/hr	63.8	102.5
Estimated Average Process Temperature - See Note 1	°F	2280	2400
Assumed CO at Furnace Exit - See Note 2	ppm	< 100	< 100
Expected Urea Consumption, 50% by Weight	gph	27.5	46.9
Average NH3 Slip, As Measured at Stack	ppmd	10	5
Reagent Distribution Strategy - Boilers 1 and 2			
◆ Zone 1 (Lower): Eight {8} Air Atomized, Standard Flow NOxOUT Injectors			
◆ Zone 2 (Upper): Four {4} Air Atomized, Standard Flow NOxOUT Injectors			
Process Design Comments			
Note 1: The temperature has been estimated using the NHI/EPRS calculation. It is fairly high since this is a short unit and the distance between the grate and the bullnose is about 24 feet. However, there are at least another 15 feet between the bullnose and the roof which may allow the flue gas to cool down somewhat.			
Note 2: Due to the very high oxygen concentration, the CO is expected to be almost completely oxidized to CO2.			

6.0 CRK and EGF SNCR SYSTEMS SCOPE OF SUPPLY

6.1 Fuel Tech Scope of Supply Summary

Description	CRK Quantity	EGF Quantity
Common Equipment ¹		
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Description	CRK Quantity	EGF Quantity
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Description	CRK Quantity	EGF Quantity
Metering, Distribution, and Injection Equipment [1]		
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Description	CRK Quantity	EGF Quantity
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
Engineering Services		
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
Other Scope		
[redacted]	[redacted]	[redacted]

Description	CRK Quantity	EGF Quantity
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

SCOPE OF SUPPLY NOTES

[redacted]

6.2 SNCR Equipment – Approximate Weights and Dimensions

Item	Description	Crookston		East Grand Forks	
		Dims (ft) (L × W × H)	Weight (lb)	Dims (ft) (L × W × H)	Weight (lb)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

6.3 Expected Total Utility Requirements Under Normal Operation

Description	Power (kW) (480V/60Hz/ 3Ø)	Service Air (scfm) (100 PSIG/ 70ºF)	Instrument Air (scfm) (100 PSIG/ 70ºF)	Dilution Water (gpm) (5PSIG/70ºF)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

UTILITY NOTES

[redacted]

6.4 Fuel Tech Engineering Scope of Supply

[redacted]

6.5 Engineering Services

[redacted]d

6.6 Scope of Supply by Others

[redacted]

[redacted]

[redacted]

7.0 DILUTION WATER AND REAGENT QUALITY SPECIFICATIONS

7.1 SNCR Dilution Water Quality Specifications

Dilution Water Analysis	NOxOUT® A	NOxOUT® HP	Unstabilized 50% Urea	NOxOUT LT [1]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

7.2 Urea Quality Specifications

Property	NOxOUT® A	NOxOUT® HP	Unstabilized 50% Urea [1]	NOxOUT® LT [2]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]

8.0 PRELIMINARY PROJECT SCHEDULE

Event	Responsibility	Weeks from Order Date
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]

Notes

[redacted]

9.0 PRICING AND PAYMENT TERMS

9.1 Budgetary CRK and EGF SNCR System Pricing

For the NOxOUT® SNCR Systems and Engineering Services described herein, Fuel Tech is pleased to provide the following budgetary pricing, FOB Point of Manufacture:

Description	Pricing (CRK)	Pricing (EGF)
NOxOUT SNCR – Common Equipment	[redacted]	[redacted]
NOxOUT SNCR – Metering, Distribution, and Injection Equipment	[redacted]	[redacted]
[redacted]		
NOxOUT SNCR System Installation		
[redacted]		

Field Service support for field services beyond those specifically noted as being included in the proposed Scope of Supply will be provided in accordance with Exhibit C-1, Fuel Tech Service Pricing Schedule included in Section 10.2.

As mentioned previously, our proposed scope of supply assumes the use of components and vendors identified in our Approved Vendor List, which is included in Section 11 of this proposal.

[redacted].

9.2 Proposed Terms of Payment

[redacted]

10.0 TERMS AND CONDITIONS

10.1 Exhibit C-3: Fuel Tech, Inc. Standard Terms and Conditions

[redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted]

[redacted]

[redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted]

[redacted] [redacted]

[redacted] [redacted]

9. CONFIDENTIALITY

(a) “Confidential Information” means the confidential or proprietary designs, processes, trade secrets, and other information owned or controlled by Fuel Tech, embodied in or relating to Fuel Tech’s design, construction and implementation of processes and systems for the reduction of NOx emissions from the specific combustion unit(s) for which Fuel Tech has been engaged to provide a technology solution (the “Site”) by urea-based or ammonia-based NOx reduction processes including (i) non-catalytic, catalytic and combined catalytic and non-catalytic processes, (ii) urea treatment and handling processes and (ii) combustion or combustion modification. For avoidance of doubt, it is understood that Confidential Information may include, but is not limited to, such designs, processes, trade secrets and other information incorporated into Fuel Tech product offerings known as NOxOUT SNCR and ULTRA. The Know-How includes, but is not limited to: computational fluid dynamics modeling for the Site; design, construction and installation of chemical injection apparatus, control systems for monitoring and controlling chemical introduction and chemical composition of combustion effluents, chemical storage and delivery apparatus, and chemical mixing apparatus; business information relating to industry standards and regulatory matters and to sources of supply of chemicals and component equipment for reduction of NOx with effectiveness; and other aspects of chemical, metering, delivery, and control for efficient operation of the Site employing urea-based selective non-catalytic reduction or urea-based combined selective non-catalytic and catalytic reduction processes alone or in combination with combustion modification.

(b) Buyer agrees that it shall hold Confidential Information received from Fuel Tech in the strictest confidence, shall not use the Confidential Information for its own benefit except as necessary to fulfill the terms of the agreement between the parties, shall disclose the Confidential Information only to employees, agents, or representatives who have a need to know the Confidential Information, shall not disclose the Confidential Information to any third party, shall not copy the Confidential Information, shall not disassemble, decompile, or otherwise reverse engineer the Confidential Information and any inventions, processes, or products disclosed by Fuel Tech, and, in preventing disclosure of Confidential Information to third parties, shall use the same degree of care as for its own information of similar importance, but no less than reasonable care.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] [redacted] ified only in writing signed by authorized representatives of each of the parties.

10.2 Exhibit C-1: Fuel Tech Service Pricing Schedule

RATES

[redacted]

	Daily Rate	Hourly Rate	Hourly Rate Travel Time	Hourly Rate Standby Time
Field Engineer	[redacted]	[redacted]	[redacted]	[redacted]
Project Engineer	[redacted]	[redacted]	[redacted]	[redacted]
Process or I&C Engineer	[redacted]	[redacted]	[redacted]	[redacted]
Project Manager	[redacted]	[redacted]	[redacted]	[redacted]
Director or Engineering Manager	[redacted]	[redacted]	[redacted]	[redacted]

VP Technology	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

NORMAL WORKING HOURS AND DAYS

8:00 A.M. to 5:00 P.M., including sufficient time for lunch, Monday through Friday, except legal holidays, at location of customer's plant.

OVERTIME

Overtime will be billed at 1.5 times the prevailing hourly rate. Overtime rates will apply to all billed time in excess of eight (8) hours on any workday or the employee's first scheduled off day (typically Saturday), in each case up to twelve (12) hours, after which the "Double Time" rates discussed below will apply.

DOUBLE TIME

Double time will be billed at two (2) times the prevailing hourly rate. Double time rates will apply to all billed time in excess of twelve (12) hours on any workday or the employee's first scheduled day off, all hours worked on the employee's second scheduled off day (typically Sunday) and all hours on observed holidays.

TRAVEL TIME

Travel time between the Fuel Tech specified location and the required destination at the commencement and conclusion of the assignment, will be billed at the hourly rates noted above. No overtime or double time will apply except for travel on Observed Holidays noted below.

STANDBY TIME

Standby Time will be billed at the Standby Rates noted above. Standby Time includes time at the jobsite when local conditions do not allow Fuel Tech personnel to perform job functions, and days when Fuel Tech personnel stay locally to a customer specified location to avoid travel home and back to the site. No overtime or double time rates will apply to the Standby Time. However, overtime rates shall apply to normal work time hours when work time and standby time combined exceeds eight (8) hours in a given day. A maximum of eight (8) hours per day of Standby Time will apply when Fuel Tech personnel are not at the jobsite for a given day.

Standby Time will also include any impacts related to COVID-19, including quarantine time.

Travel, lodging and living expenses as defined below shall be applicable to all Standby Time.

VIRTUAL SUPPORT TIME* OR OFFICE TIME*

Virtual Support time will be billed at the Standby Rates noted above. Virtual Support time includes FT personnel assisting with Customer requested activities. Daily time in excess of eight (8) hours may be subject to Overtime or Double Time as defined above.

Office Time will be billed at the Standby Rates noted above. Office Time includes report writing and time used to prepare for a site visit. No overtime or double time rates will apply for Office time. A maximum of eight (8) hours per day of Office time will apply.

EXPENSES

[redacted]

[redacted]

[redacted]

FUEL TECH OBSERVED HOLIDAYS AND RATE

[redacted]

[redacted]

[redacted]

GENERAL CONDITIONS

[redacted]

[redacted]

[redacted]

[redacted] [redacted]

SPARE PARTS

[redacted]

RENTAL EQUIPMENT

[redacted]

[redacted] [redacted]

[redacted] [redacted]

11.0 SUPPORTING DOCUMENTATION

11.1 Marketing Brochures and Related Information

11.1.1 Fuel Tech – Environmental Solutions for Power & Industry

11.1.2 NOxOUT and HERT SNCR

11.1.3 Modeling Services, CFD and Experimental

11.1.4 NOxOUT Reagent Licensees, March 2020

11.1.5 Fuel Tech Approved Vendor List, June 2019

Environmental Solutions for Power & Industry

FUEL TECH®
Technologies to enable clean efficient energy

Highly Integrated, Multi-pollutant Control Systems

Fuel Tech develops and commercializes state-of-the-art proprietary technologies for air pollution control, process optimization, water treatment, and advanced engineering services. These technologies enable customers to operate in a cost-effective and environmentally sustainable manner.

- Expertise based on capabilities in research & development, advanced process modeling, and project execution
- More than 30 years of experience results in successful implementation of these systems and programs worldwide
- Fuel Tech has 1,200+ installations worldwide and is traded on the NASDAQ (FTEK)

Air Pollution Control

Fuel Tech has developed a variety of state-of-the-art, proprietary Air Pollution Control technologies that are focused on multi-pollutant control generated from a variety of combustion sources and utlize a wide variety of fuels.

APC Expertise:
- NO_X Reduction
  - *SNCR, LNB, OFA, SCR*
- Particulate Control
  - *ESP & FGC*
- Urea (ULTRA®) and ammonia feed systems for SCR

Chemical Technologies

Chemical Technologies improve the efficiency, reliability, and environmental performance of boilers operating in the electric utility, industrial, pulp and paper, and waste-to-energy markets.

Programs for chemical technologies also mitigate SO_3-related issues and improve unit heat rates and efficiency to reduce greenhouse gasses.

Minimizes:
- Slagging & Fouling • Corrosion • Opacity • Acid plume

Water Technologies

DGI™ Dissolved Gas Infusion is an innovative alternative to standard aeration technologies, utilizing a patented, high-velocity nozzle to produce smaller bubbles.

The greater efficiency allows optimization of biological treatment, chemical oxidation, and environmental remediation processes for ponds, tanks, and basins.

Lower operating costs • Greater surface area • Increased residence time

Global Presence, Global Solutions

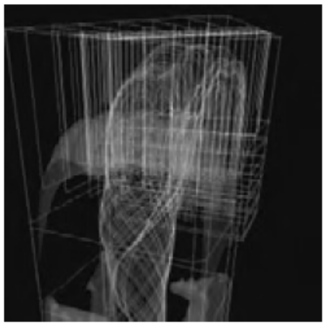
FUEL TECH®
Technologies to enable clean efficient energy

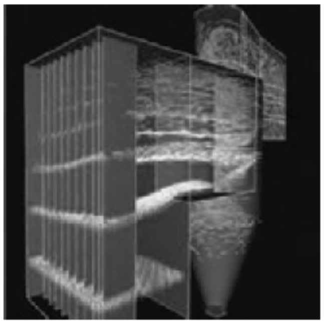
1,200+ Installations
Across Four Continents

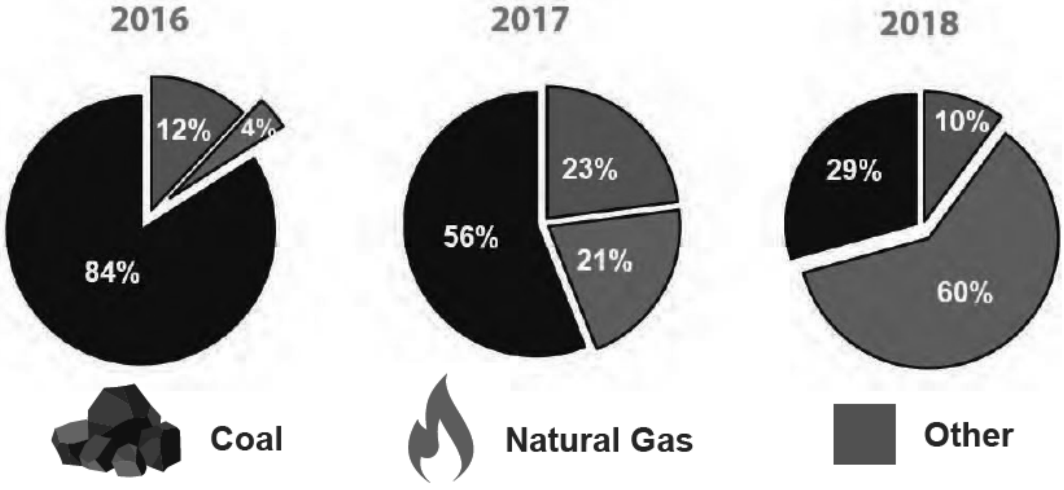
Technology	No. Installed/MWs
SNCR	640/55,000
LNB/OFA	110+/16,400
SCR	150+/63,200
ULTRA®	270+/28,000
ESP/FGC	110+/20,000
Chemical/TIFI®	110+/22,000

Innovative Technology, Engineering, and Design

- 3-D Visualization used to create custom solutions
- Computational Fluid Dynamics (CFD) Modeling of customer processess
- Chemical Kinetics Modeling with CFD to develop solutions for complex chemistries
- Injection Modeling to evaluate and optimize performance







Fuel Tech's adaptable solutions are reflected in company revenues by domestic fuel source

Worldwide Locations

27601 Bella Vista Parkway | Warrenville, IL 60555 USA | www.ftek.com
(USA) +1 800.666.9688 • (Italy) +39.0331.701110

NASDAQ: FTEK

SNCR
NOxOUT® and HERT™ Processes

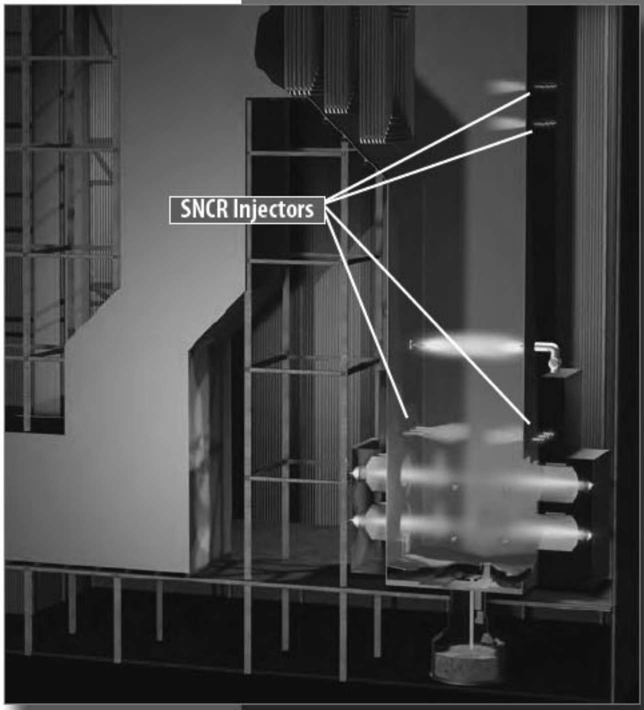
Proven solutions for flexible and cost-effective NO_X reduction

Fuel Tech's urea-based Selective Non-Catalytic Reduction (SNCR) process is a post-combustion NO_x reduction method that reduces NO_x emissions through a controlled injection of an aqueous urea solution into the combustion gas path of fossil-fired and waste-fired boilers, furnaces, incinerators, or heaters.

Fuel Tech has enhanced the basic SNCR technology by developing chemical injection hardware, widening the applicable temperature range, and applying process control expertise required for commercial applications.

Fuel Tech has two urea-based SNCR technologies: NO_xOUT® systems, which utilize low energy, air atomized injectors, and HERT™ High Energy Reagent Technology systems, which utilize mechanically atomized injectors and carrier air for injection into the furnace.

The NO_x- reducing reaction is temperature sensitive: the optimum temperature range is specific to each application. The reagent needs to be distributed within this optimum temperature zone to obtain the best performance. The most commonly used reagent consists of a 50% urea solution. This reagent is readily available and requires no special safety precautions for handling.



SNCR Injection Process

SNCR Processes
Fuel Tech's SNCR processes are designed with the aid of Computational Fluid Dynamics (CFD) and Chemical Kinetic Modeling (CKM) in addition to results from field tests. The CFD model simulates flue gas flows and temperature inside a unit while the CKM calculates the reaction between urea and NO_x based on temperature and flow information from CFD. The combination of these two models determines the optimum temperature region and the optimum injection strategy to distribute the reagent.

NO_XOUT® Process Injection	SNCR Technology	HERT™ Process Injection
• High momentum injectors • Maximize performance • Adjustable for NO_X reduction downstream of injection point	• CFD/CKM Modeling • Reliable equipment • On-site optimization	• High energy, low momentum injectors • Maximize performance with minimal ammonia slip • Localized NO_X reduction

25-50% NO_X Reduction

- Over 590 SNCR systems installed worldwide
- Average NO_X outlet for systems >400MW is less than 0.16 lb/MMBtu
- Easy to retrofit – little downtime required
- Utility and industrial applications
- Guaranteed performance
- Safe reagent

FUEL TECH
Technologies to enable clean efficient energy

SNCR Systems

We have over 1,000 APC system installations worldwide on wide range of fuels and combustion units.

Commercial Combustion Units

- Tangentially-Fired Utility Boilers
- Cyclone-Fired Utility Boilers
- Wall-Fired Utility Boilers (wet & dry)
- Refinery Crude Heaters and CO Boilers
- Sludge Combustors
- Industrial Power Boilers
- Municipal Waste Combustors
- Incinerators
- Circulating Fluidized Bed Boilers
- Stoker-Fired Boilers Burning Wood and Coal
- Package Boilers

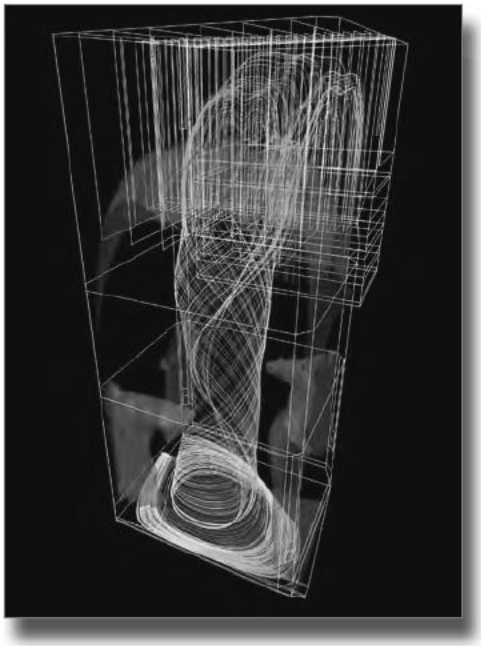
Process Combustion Units

- Cement Kilns
- Glass Furnaces
- Ethylene Furnaces
- Calciners
- Coke Ovens
- Lime Kilns

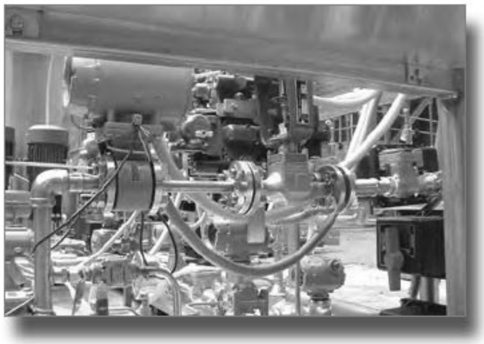
Fuels:

- Coal
- Lignite
- Oil
- Gas
- Sludge
- Wood
- Biomass
- Refinery/CO Gas

Each application has a customized design and injection strategy to maximize NO$_X$ reduction



CFD Models of NO$_X$OUT® and HERT™ SNCR systems determine injector locations to maximize coverage resulting in optimal NO$_X$ reduction.



Independent Zone Metering Module

Chemical injectors developed by Fuel Tech facilitate the reagent distribution. The NO$_X$OUT® injection system utilizes air-atomized injectors which direct the urea solution into the combustion gas path. The droplet size distribution and spray coverage promote efficient contact between the chemical and the NO$_X$ in the flue gas.

The HERT™ injection system utilizes mechanical atomizers which carry the urea into the furnace using a high energy air stream. Fuel Tech evaluates both for each specific application and offers the best solution to meet our customer's needs.

Fuel Tech's SNCR systems provide effective boiler load following capabilities to maximize overall NO$_X$ reduction.

Through computer modeling and proven field experience, an injection strategy is developed that makes use of multilevel injection, control of reagent concentration, droplet size and spray patterns, as well as jet penetration.

NO$_x$OUT® and HERT™ systems are applicable on various types of units firing many different fuels, which has been verified by years of field-testing. Since SNCR is a post-combustion process, unit size, boiler type and fuel type can be accommodated in the customized process design.

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Modeling Services

CFD & Experimental

Support system performance guarantees through modeling technologies.

Fuel Tech's experimental (physical) modeling studies combined with Computational Fluid Dynamics (CFD) modeling allow for an insightful understanding of existing flow conditions and effective design of corrective devices such as turning vanes, ash screens, injection systems and static mixers for each unique project.

We specialize in fluid dynamics modeling of air pollution control equipment. Scale models of 1:4 to 1:18 have been built for testing for installations in Europe, North America and Asia. Our focus continues to be the delivery of the most accurate and innovative solutions for our customers.

By combining computational and experimental modeling for ESPs, Fuel Tech can predict fluid behavior in new and existing ESP installations, identify flow problems, analyze the process conditions and provide solutions. Corrective flow devices can then be designed, tested and optimized to ensure that flow characteristics meet industry standards.

Innovative techniques are used in physical flow modeling to improve performance in flow critical equipment. Our flow models are constructed quickly and accurately using CNC cut steel as a skeleton, while clear plastic is tested using the latest in flow analysis equipment.

The combination of unique construction techniques, state-of-the-art technology and years of experience enables model studies to be performed in half the time required by our competitors, thereby providing our customers with the confidence and guarantees needed to proceed with construction or retrofitting.

Physical Models designed to 1/12th scale, combined with CFD modeling.

Selective Catalytic Reduction (SCR) processes are modeled to ensure that the catalyst is effective and catalyst life is extended for as long as possible. Proper mixing of flue gas and good flow and velocity profile are required to prevent ammonia slip and ensure that NO_X emissions are minimized.

Modeling of Fabric Filters (Baghouses) can be used to predict and solve problem areas of wear and particulate fallout, while reducing overall pressure losses.

Flue Gas Desulphurization (FGD) systems are modeled to prevent poor performance, while solving other problems associated with wet scrubber processes such as:

- Inlet duct liquid pullback
- Mist eliminator performance
- Excessive pressure losses
- Fan inlet flow distribution
- Spray coverage
- Liquid collection

Optimization projects:

- Reduce system pressure losses
- Improve velocity, temperature, gas species and ash distributions
- Prevent in-duct ash and fallout

Fuel Tech has experience modeling and optimizing the following types of equipment:

- Boiler Combustion
- Low NO_X Burners
- Over-Fire Air
- Electrostatic Precipitators (ESP)
- Selective Non-Catalytic Reduction Process (SNCR)
- Selective Catalytic Reduction Process (SCR)
- Fabric Filter (Baghouses)
- Flue Gas Desulphurization System (FGD)

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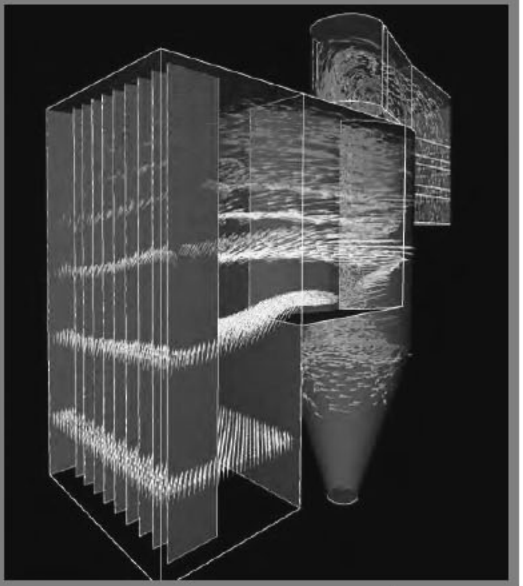
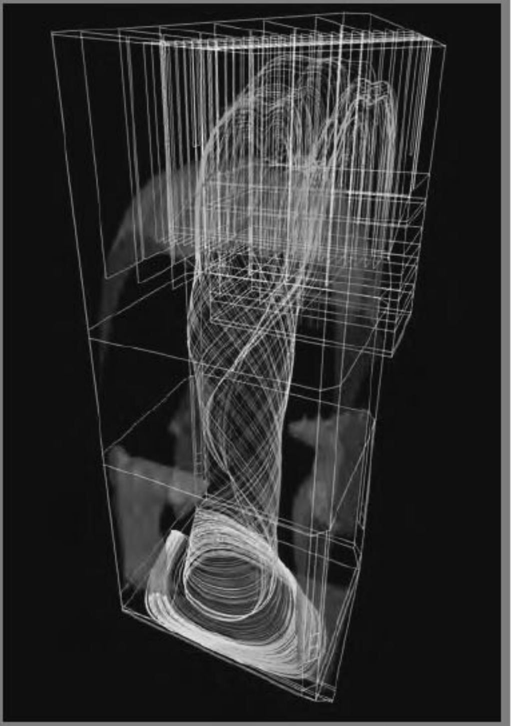
Modeling Services

CFD Models designed to accurately predict system performance.





Computational Fluid Dynamics (CFD)

Every Fuel Tech product installation has a custom process model supporting it. The model begins with a Computational Fluid Dynamics (CFD) simulation.

CFD models generate predictions of operating temperatures, velocities and other variables from a virtual replication of real-world geometry and operating inputs. Once the base model is generated, we "fly" through the model, using our proprietary visualization software; designed to make explicit to the engineer the complex behaviors of combustion flows. Fuel Tech engineers can explore their models from any perspective with the software and engage the customer in the design stage and tap into the expertise of their plant's experts.

Additional modeling is performed for each unit depending on the type of Fuel Tech application. Once a complete understanding of the process conditions is achieved, a chemical injection strategy is optimized.

Fuel Tech has developed its own chemical spray models specific to boiler and duct conditions, and these models have been validated with both laboratory characterizations of our sprays as well as field performance during 20 years of applications.

Fuel Tech engineers use visualization software to reposition sprays dynamically and gauge the effect on desired performance. CFD simulation of the original model with spray injection provides a more precise mapping of chemical performance.

This proprietary visualization software provides our engineers the ability to show our designs in an immersive, interactive way. Our engineers recognize the information contained in their simulation datasets more rapidly and with greater precision.

Group visualization sessions in our stereovision projection laboratory in Warrenville, IL allow for enhanced design creativity and further risk management. Our designers and sales personnel communicate visually what they have discovered, allowing customers a complete understanding of our recommendations. Customer engagement and feedback on what they see in the virtual environment enriches the design process and further increases quality.

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FUEL TECH®
Technologies to enable clean efficient energy

NOxOUT® Reagent Licensees

Licensee	Address	Contact Person	Telephone/Fax
CDI, Inc.	471 W. Lambert Rd, Suite 100 PO Box 9083 Brea, CA 92821	Luis Cervantes email: ldc@cervantesdistribution.com	714.990.3940 ext. 302 714.329.2281 (cell) 714.990.4073 (fax)
Distribution Points	– Crossett, AR – Casa Grande, AZ - City of Industry, CA – Imperial, CA – San Jose, CA – Stockton, CA – Greeley, CO – Jacksonville, FL – Augusta, GA – Kimberly, ID – Baltimore, MD – St. Paul, MN – Albany, NY – Elizabeth, NY – Cincinnati, OH – Lima, OH – Deer Island, OR – Russellville, SC – Memphis, TN – Houston, TX – Lufkin, TX – Pasco, WA		
QLF	328 Bucklin Street Suite 200 LaSalle, IL 61301	Randy Saini email: randy@qlf.com	815.224.1553 815.228.5711 (cell)
Distribution Points	–La Salle, IL – Dunlap, IA – Wellsville, OH – Menomonie, WI		
PCS Nitrogen, Inc/Nutrien	1101 Skokie Blvd Northbrook, IL 60062	Jim Jordan Email: James.W.Jordan@Nutrien.com	847.849.4377 847.687.8352 (cell)
Distribution Points	– Augusta, GA - Lima, OH		
Monson Companies, Inc.	One Runway Rd PO Box 2405 South Portland, ME 04116-2406	Jeff Pellerin email: **orders@monsonco.com**	207.885.5072 x 423 207.885.0569 (fax)
Distribution Points	– South Portland, ME		
The Andersons, Inc.	480 W. Dussel Drive PO Box 119 Maumee, OH 43537	John Kevern email: John_Kevern@AndersonsInc.com	419.973.3278 (cell) 419.891.6317 (office)
Distribution Points	– Logansport, IN – Maumee, OH		
Colonial Chemical Co.	78 Carranza Rd Tabernacle, NJ 08088	David DiMeo email: DDiMeo@colonial-chemical.com	484.534.9190 (office) 484.374.0922 (cell)
Distribution Points	– Frederick, MD – Tabernacle, NJ-Monroe, LA – Hempstead, TX –Webberville, MI-Raeford, NC – Morrisville, PA – St. Paul, MN – Shakopee, MN		
Musket Corporation	2929 Allen Parkway Suite 4100 Houston, TX 77089	Dave D Michael email: dave.michael@musketcorp.com	303.519.9022 (cell)
Distribution Points	– Kingman, AZ – Louisville, KY -Salt Lake City, UT – Albuquerque, NM – Memphis, TN-Alorton, IL – Morrow, GA – Big Spring, TX – Quakertown, PA – Lebanon, TN – Aurora, CO – El Paso, TX – Blue Island, IL		

Information Needed by Licensees:

- Company Name
- Location
- Scheduled Start-Up Date
- If rail delivery- specify railroad
- NOxOUT® Reagent Type Required (A,HP,LT)
- NOxOUT® Reagent Usage Rate
- NOxOUT® Reagent Storage Tank Size

APPROVED VENDOR LIST

Mechanical, Instrumentation, and Materials Manufacturer's List

Fuel Tech's standard equipment is fabricated with parts and devices from the following manufacturers. Where multiple manufacturers are indicated, any one manufacturer may be used. This list is not complete but comprises the significant components of FTI equipment and scope. A part or device of equal quality and application may be substituted if the part or manufacturer listed below is no longer available.

ITEM	MANUFACTURER
Actuator – electric, valve (small)	Asahi, Indelac, Electra
Actuator – electric (for windbox dampers)	Harold Beck & Sons
Actuator – pneumatic, (rack and pinion, quarter turn)	Asahi, Sharpe, Xomox, Flotite/Aircon
Actuator – pneumatic, linear (for burner tilts)	Harold Beck & Sons
Agitator, liquid	Chemineer
Analyzer, NOx	SICK
Centrifugal Blower (ULTRA & HERT)	AirPro Fans, Chicago Blower
Regenerative Blower (ULTRA 5)	GAST, Rotron, Republic
Burner, T-fired	RV Industries
Burner, gas (ULTRA)	Forney, Maxon
Burner, nozzle, T-fired	RV Industries
Burner, oil (ULTRA)	Forney, Maxon
Burner, wall	Fuel Tech
Catalyst	Johnson Matthey, CERAM, Hitachi, Cormetech, Umicore (Haldor Topsoe)
Coal Pipe	CL Smith
Controller, single loop	Yokogawa
Diaphragm seal, gauge	Rheotemp, WGC
Enclosures, fiberglass, equipment	RDI Enclosures
Enclosures, metal, equipment	RDI Enclosures
Fitting, compression	Parker
Heater, sheath design	Warren Electric, Thermon, Tempco
Heater, open coil	Farnam
Hose, flexible elastomeric	Parker, Saint Gobain
Indicator, flow, sight	ABB/Fisher-Porter, Kobold, King
Indicator, pressure	Rheotemp, WGC
Indicator, differential pressure	Dwyer, Ashcroft

APPROVED VENDOR LIST

ITEM	MANUFACTURER
Indicator, temperature	Ashcroft, Wika
Indicator, temperature, thermowell	Ashcroft, Pyromation
Injector, automatic retract	Fuel Tech
Injector, multi-nozzle lance (MNL)	Fuel Tech
Injector, wall, ULTRA, SCR	Fuel Tech
Injector, MNL, retract	Diamond Power
Limit Switch, On/Off Valve Actuator	Topworx, Moniteur
Motor	Baldor, Reliant, Grundfos
Pipe supports	Stauff, Unistrut
Pump, metering	Milton Roy, Neptune, Grundfos
Pump, multistage centrifugal (water, urea)	Grundfos
Regulator, air pressure	Parker, Norgren, ASCO, Fisher, Control Air
Sonic horns	General Electric
Strainer, liquid	Eaton, Mueller
Switch, pressure	Ashcroft, SOR
Switch, differential pressure	Ashcroft, SOR
Tank, FRP urea storage	GPI, Strand
Temperature Monitor (optical)	Diamond Power
Thermocouple	Pyromation
Transmitter, density	Emerson Micromotion, Yokogawa
Transmitter, flow, magnetic	Efector
Transmitter, flow, vortex	Efector
Transmitter, flow, thermal mass	Efector, Fox, ABB
Transmitter, pressure	Efector
Transmitter, pressure, tank level	Efector
Transmitter, pressure differential	Efector
Valve, ball	Flo-tite, Sharpe, In-Line, Powell, Parker
Valve, ball, gauge isolation	Jomar, Ohio
Valve, Butterfly	Flo-tite, Powell
Valve, check	Parker, Islip, Ladish, Titan, Crane, Check Rite
Valve, control	Badger Research

APPROVED VENDOR LIST

ITEM	MANUFACTURER
Valve, globe	Aloyco, Powell
Valve, needle	Parker
Valve, pressure regulating	Cash Valves, Cash-Acme, Fisher, Cashco
Valves, relief	Kunkle, Crosby, Anderson Greenwood
Valve, root (plug)	Parker
Valve, solenoid	ASCO, Festo
Valve, tubing	Parker

FUEL TECH®
Technologies to enable clean efficient energy

APPROVED VENDOR LIST

Electrical Manufacturer's List

Fuel Tech's standard equipment is fabricated with parts and devices from the following manufacturers. Where multiple manufacturers are indicated, any one manufacturer may be used. This list is not complete but comprises the significant components of FTI equipment and scope. A part or device of equal quality and application may be substituted if the part or manufacturer listed below is no longer available.

ITEM	MANUFACTURER
Breaker, circuit (module panels)	Square D, Cutler-Hammer, Allen-Bradley, Schneider
Breaker, main	Square D, Cutler-Hammer, Allen-Bradley, Schneider
Burner management system (ULTRA)	Forney, Honeywell
Conduit, flexible	Sealtite, Electraflex, Anaconda
Contactor	Square D, Cutler-Hammer, Allen-Bradley, Schneider
Cooler, vortex	ISC
Disconnects, fused (module panels)	Square D, Cutler-Hammer, Allen-Bradley, Schneider
Drives, variable frequency (VFD)	Allen-Bradley, Schneider
Enclosures, stainless steel & non-metallic	Hoffman, IEC, Rittal, Saginaw
Fan, panel, circulation/cooling	Newark
Fuse blocks	Square D, Cutler-Hammer, Allen-Bradley, Schneider
Fuses, panel-mounted	Bussman
Ground bus	Square D
Human Machine Interface (HMI)	Allen-Bradley Panel View
Light, pilot (indicator)	Square D, Cutler-Hammer, Allen-Bradley, Schneider
Line filter	Emerson SOLA
Panel, branch circuit	Square D, Cutler-Hammer, Allen-Bradley, Schneider
Power supply (module panels)	Emerson SOLA
Programmable logic controller (PLC)	Allen-Bradley (Compact Logix), Siemens
Pushbutton	Square D, Cutler-Hammer, Allen-Bradley, Schneider
Receptacles, general	Bryant, General Electric, Hubbell
Relay, control	Square D, Cutler-Hammer, Allen-Bradley, Schneider
Starter, magnetic motor	Square D, Cutler-Hammer, Allen-Bradley, Schneider
Switch, proximity	Norgren
Switch, heavy duty	General Electric, Square D, Cutler-Hammer
Switch, selector	Square D, Cutler-Hammer, Allen-Bradley, Schneider
Terminal blocks	Square D, Phoenix, Allen-Bradley, Schneider

APPROVED VENDOR LIST

ITEM	MANUFACTURER
Timer	Square D, Cutler-Hammer, Allen-Bradley, Schneider
Transformer, dry	Square D, Acme
Transformer, panel-mounted	Jefferson, Acme
Wire, control	Belden
Wire, power, 600V, multi conductor, copper	Southwire, Belden, Okonite
Wire, signal	Belden
Wiring duct	Panduit

From: Raetz, Gregory
To: Bouchareb, Hassan (MPCA)
Cc: Doug Emerson
Subject: RE: Regional Haze :: Dry Sorbent Injection Information
Date: Tuesday, April 5, 2022 5:04:36 PM
Attachments: image001.jpg

Hassan,

Here is some additional information regarding the items below:

1. TRONA consumption and cost was taken directly from the vendor quote provided by United Conveyor Corporation, UCC Proposal Q21136, September 10, 2021. This proposal included costs for pre-milled sodium bicarbonate and un-milled trona, when corrected for injection rate and annual capacity factors, was approximately $355/ton and $230/ton. The annual costs were based on injection rates of greater than 300 lb/hr for CRK boilers and greater than 70 lb/hr for EGF boilers to achieve the high level of SO2 control. As additional note, reagent prices are expected to continue to rise sharply based on current supply/demand issues.
2. The electrical demand for the baghouse and DSI systems was based on vendor design data (i.e., required blower HP) and ACSC electrical costs. The HP required for blowers, compressed air, etc. was converted to kW to calculate annual costs incorporating applicable capacity factors (6500 hr/yr). The total kW demand for each system is listed in the table and costs were based on $0.06/kW-hr.
3. Annual costs for bag replacement and ash disposal were scaled from a similar project design from a utility project analysis completed several years ago. The costs were scaled for capacity, but not adjusted for present day dollars, so they should be somewhat conservative on the low side. Just for curiosity, I took a look at SMBSC costs and it looks like we are in the same ballpark.

Hopefully, this works. Let me know if you need more detail.

Greg

Gregory J. Raetz, PE
D 763.278.5905 **M** 612.559.1130

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From: Bouchareb, Hassan (MPCA) <hassan.bouchareb@state.mn.us>
Sent: Friday, March 25, 2022 4:21 PM
To: Raetz, Gregory <Gregory.Raetz@hdrinc.com>
Cc: Doug Emerson <Demerson@crystalsugar.com>
Subject: Regional Haze :: Dry Sorbent Injection Information

Hi Greg,

Quick question for you regarding the DSI cost estimates for ACS. In the DSI spreadsheets, the direct annual costs include a footnote that they are based on site-specific design and vendor quote. I was hoping you could provide some clarity on how the following values were determined for both Crookston and East Grand Forks (as they are just hard entered in the spreadsheet):

- Solvent (Trona) consumption and cost
- Solids fly ash disposal quantity and cost
- Fabric Filter bag replacement
- DSI electric demand and cost
- Fabric Filter electric demand and cost

Let me know if you have any questions.

Thanks again!

Hassan M. Bouchareb | Engineer
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Environmental Analysis & Outcomes Division
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Our mission is to protect and improve the environment and human health.

From: Raetz, Gregory
To: Bouchareb, Hassan (MPCA); Doug Emerson
Subject: RE: Regional Haze :: American Crystal Sugar NOX calculations
Date: Thursday, May 5, 2022 2:58:21 PM
Attachments: image001.jpg
image002.jpg
image003.jpg
image004.jpg

Hassan,

Regarding the retrofit factor of 1.5. The higher retrofit factor is based on engineering judgement and experience with similar projects at ACSC facilities. Both the EGF and CRK are old facilities. EGF was built in the mid 1970s and CRK was built in the early 1950s. Over the years, a number of changes have been made to the facilities, including things such as production expansions, boiler modifications, fuel handling equipment changes, control equipment additions. All of these changes have led to a decrease in available space for new additions as well as increased the complexity of equipment interferences etc. In the past decade changes to overfire air systems have resulted in retrofits to much of the boiler duct work, also both facilities have also had powdered activated carbon silos and injection systems added. Both of these changes have required accommodation of major equipment changes (i.e., fans, foundations, silos, etc.) that have decreased the room for additional changes.

Some of the specific concerns with SNCR system addition:

1. Existing infrastructure will need to be relocated to allow room for installation of urea or ammonia storage for SNCR systems. Depending on the location this will involve relocating onsite rail lines, relocation of molasses storage tanks, and/or rerouting fuel delivery and unloading.
2. Based on previous project work, contingency must account for unexpected demolition of previously abandoned infrastructure (i.e., old foundations, piping etc.) when constructing new foundations and placing equipment. General excavation onsite generally has a much higher cost factor than elsewhere.
3. Internal placement of SNCR injection equipment will require extensive work to avoid interferences and relocation of existing piping. As a result of retrofitted OFA ducts, spacing and accommodation of SNCR injectors will be difficult and costly.
4. Expansion of electrical systems and control rooms will be necessary to accommodate pumps, mixers and controls for SNCR. Currently, as a result of past projects, there is little room available in the boiler area and relocation of existing equipment will likely be necessary.
5. Given the campaign based nature of ACSC operations all maintenance and construction projects must occur during a limited window of downtime in the late summer. Given the large number of general projects that occur, timing of projects in a limited space will be difficult and additional mobilization fees and demands will result in higher construction costs.
6. As a general comment given potential timing for the project and current events, increased costs due to general equipment supply issues as well labor availability will play a large factor in final project costs.

Let me know if you need more.

Greg

Gregory J. Raetz, PE
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From: Bouchareb, Hassan (MPCA) <hassan.bouchareb@state.mn.us>
Sent: Thursday, May 5, 2022 2:21 PM
To: Raetz, Gregory <Gregory.Raetz@hdrinc.com>; Doug Emerson <Demerson@crystalsugar.com>
Subject: RE: Regional Haze :: American Crystal Sugar NOX calculations

Hi Greg,

That does help explain things. I'll be curious to see what subsequent tests end up resulting in for a lb/hr NO_X value. This was one area that the FLMs noticed as well, so if there is any documentation or write-up that the testing company provided, it might be helpful to have that available in case of comments/questions.

Any thoughts on the retrofit factor (1.5 value) used? This value is one of the cost estimate values that I believe I'm still missing documentation for. I'm working through the documentation portion for the SIP document overall and the justification for using that value is something I'll need to support its use.

Thanks again!

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From: Raetz, Gregory <Gregory.Raetz@hdrinc.com>
Sent: Thursday, May 5, 2022 9:53 AM
To: Bouchareb, Hassan (MPCA) <hassan.bouchareb@state.mn.us>; Doug Emerson <Demerson@crystalsugar.com>
Subject: RE: Regional Haze :: American Crystal Sugar NOX calculations

Hi Hassan,

Sorry for the delay. I do have some information for you. Doug and I were able to connect with the stack test firm and discuss the differences in lb/hr vs lb/MMBtu. Bottom line, we believe the lb/MMBtu numbers are the most accurate for annual emissions and regulatory compliance; therefore, I think they are the most appropriate for the reginal haze analysis.

The stack test company confirmed that the lb/hr value was calculated based on a direct measurement of the stack velocity using a pitot tube, measured stack dimensions and the measured concentration (ppm) of NOx. There are several points of error that have an impact on this value. 1) the simple pitot tube flow measurement did not account for pitch and yaw of the stack gas flow introduced from cyclonic stack flow, therefore it has a tendency to over state the stack velocity. 2) the pitot tube measurement was taken in one single location and does not account for stack wall effect which results in a lower amount of flow near the stack walls due to friction. Therefore, when you apply the single measured velocity to the entire stack cross-sectional area, you again introduce some bias on the high side. 3) moisture levels are measured and corrected for using a wet measured flow with a dry analyzer ppm, but still are a point that could introduce some error.

In summary, it is suspected that the calculated lb/hr values are skewed high. This issue is compounded when you assume that same maximum lb/hr rate is emitted for the entire hours reported for boiler operation. Under normal operations the boilers typically operate at about 70% load with swings up to the 80's once in a while. Testing occurs at 90+%. Also, the hours reported for operation include some downtime, some startup and shut down, and are generally very conservative. By using the conservative hours with the max lb/hr emission rate (which includes some error on the high side), the NOx emissions reported in the emission inventory are conservatively high. Because these are basically used for fee purposes, ACSC is comfortable reporting this higher level. However, a more accurate view of actual annual emissions would be to incorporate the annual heat input from the actual amount of coal burned (i.e., the MMBtu/yr and lb/MMBtu values).

During the next stack test, I think we will do some extra testing to get a more accurate velocity over a full traverse of the stack and account better for cyclonic flow and other issues to see if we can get a better number.

Let me know if this helps.

Greg

Gregory J. Raetz, PE
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From: Bouchareb, Hassan (MPCA) <hassan.bouchareb@state.mn.us>
Sent: Wednesday, May 4, 2022 3:18 PM
To: Raetz, Gregory <Gregory.Raetz@hdrinc.com>; Doug Emerson <Demerson@crystalsugar.com>
Subject: RE: Regional Haze :: American Crystal Sugar NOX calculations

Good afternoon!

I don't think I've seen a response to my questions on NO_X calculations and the retrofit factor used. Any updates you can provide would be much appreciated.

Let me know if you have any questions.

Thanks!

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From: Bouchareb, Hassan (MPCA)
Sent: Wednesday, April 20, 2022 9:42 AM
To: Raetz, Gregory <Gregory.Raetz@hdrinc.com>; Doug Emerson <Demerson@crystalsugar.com>
Subject: RE: Regional Haze :: American Crystal Sugar NOX calculations

Good morning Greg and Doug,

Any updates you can provide on the NO_X calculations?

I also was hoping you could help me with one other question. I'm going back to earlier comments and I'm not finding a discussion on the use of a 1.5 retrofit factor in the control cost manual spreadsheets. I don't see a discussion in the supplementals previously provided, but maybe I'm not looking in the right place.

Would you please point me in the right direction if it is in materials previously provided, or if not provided, send me justification for using that 1.5 retrofit factor?

Thanks!

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From: Bouchareb, Hassan (MPCA)
Sent: Tuesday, April 5, 2022 4:27 PM
To: Raetz, Gregory <Gregory.Raetz@hdrinc.com>; Doug Emerson <Demerson@crystalsugar.com>
Subject: RE: Regional Haze :: American Crystal Sugar NOX calculations

Hi Greg,

Thanks for looking into things, I'll be curious to see what the test company comes up with too. Hopefully it's just a simple calculation error/typo. I'm generally leaning towards it being an error in the lb/hr values as well, plus that's a better problem to have emissions being overestimated than underestimated.

I look forward to hearing from the testing company.

Thanks!

Hassan M. Bouchareb | Engineer
Minnesota Pollution Control Agency (MPCA)

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From: Raetz, Gregory <Gregory.Raetz@hdrinc.com>
Sent: Tuesday, April 5, 2022 3:32 PM
To: Bouchareb, Hassan (MPCA) <hassan.bouchareb@state.mn.us>; Doug Emerson <Demerson@crystalsugar.com>
Subject: RE: Regional Haze :: American Crystal Sugar NOX calculations

---

Hi Hassan,

I took a look back to see where the baseline NOx numbers came from. I found the test reports and included excerpts below showing the lb/MMBtu numbers. I know the measured value was a concentration (ppm) that was converted to lb/MMBtu using the measured excess O2 and the F-factor equation found in 40 CFR, Method 19. This is pretty standard practice and bases the emissions on stoichiometric flowrate that would be produced from a given heat input of fuel.

I double checked the lb/MMBtu conversion from the raw measured ppm. It appears to be correct. This leads me to believe something is wrong/inconsistent with the lb/hr calculation. I have looked through the test report but cannot locate sufficient detail in the calculation notes to see where things went off track. I have contacted the test company to see if I can get clarification.

In the meantime, I would assume the lb/MMBtu numbers are correct and that the emission inventory is over reporting emissions. We used the lb/MMBtu numbers in the CCM calculation spreadsheet, which then estimated emission reductions. The lb/MMBtu numbers would be more reflective of annual operations and annual heat input and thus more appropriate for the annual control costs. The short-term lb/hr number shows a worst-case “snapshot” at extreme load and would tend to overpredict emissions if extrapolated out for a whole year.

I will let you know what I learn from the test company regarding the lb/hr values.

Also, I will get you some support data for your other question regarding reagent and energy usage. In short, it was scaled from data from a similar project.

Gregory J. Raetz, PE
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From: Bouchareb, Hassan (MPCA) <hassan.bouchareb@state.mn.us>
Sent: Thursday, March 31, 2022 9:41 AM
To: Doug Emerson <Demerson@crystalsugar.com>; Raetz, Gregory <Gregory.Raetz@hdrinc.com>
Subject: Regional Haze :: American Crystal Sugar NOX calculations

Good morning,

Adding a little bit more information to my late afternoon call yesterday to both of you. I was doing some cross checking of emissions data yesterday when I noticed that there was some conflicting information for NO_X rates at Crookston. I don't believe this same issue exists for the East Grand Forks facility, as NO_X CEMS are installed at East Grand Forks vs. Crookston using a portable CEMS setup for testing requirements.

Looking at past test data, the boilers at the ACSC facilities all use NO_X CEMS for the tests. This is where the ~0.33 lb/MMBtu value comes from, but it also comes with a lb/hr NO_X rate. The performance test is specifically to determine the lb/hr rate that Crookston has to test against for a permit limit, but the lb/MMBtu values are included in the test data when you look past the summary.

	NO_X Lb/MMBtu	MMBtu (2019)	NO_X Tons (2019)		NO_X Lb/hr	Hours (2019)	NO_X Tons (2019)
Boiler 1 (137 MMBtu/hr)	0.321	538,291	**86.4**		63.6	6,336	**201.5**

Boiler 2 (137 MMBtu/hr)	0.330	538,291			68.6	6,312	
Boiler 3 (165 MMBtu/hr)	0.324	717,709			65.1	6,192	

$_X$ lb/MMBtu and lb/hr values are from an October 2017 performance test at Crookston.

** MMBtu and operating hours are from 2019 emission inventory submittal for Crookston.

The lb/hr rate is what ACSC used to calculate annual emissions reported to the 2019 emissions inventory (with total operating hours for the particular boilers), but this doesn't match up with the value when calculated with lb/MMBtu and heat input data reported. Something obviously doesn't add up here. For example, Boiler 1 operating at full capacity (137 MMBtu/hr at 0.321 lb/MMBtu) would have to operate for ~9,164 hours in a year to reach the reported 201.5 tons of NO_X emissions.

It looks like either the fuel consumption, the NO_X emission rate (lb/hr or lb/MMBtu), or some combination of the three are incorrect.

Happy to discuss further if you have any questions.

Thanks!

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January 29, 2020

Mike Wagner, Owner
Boise White Paper LLC
400 2nd Street
International Falls, MN 56649

RE: Request for Information - Regional Haze Rule, Reasonable Progress, Four Factor Analysis

Dear Mr. Wagner:

The Minnesota Pollution Control Agency (MPCA) is currently preparing information for the second planning period (Round 2) comprehensive update to Minnesota's Regional Haze State Implementation Plan (SIP) as required by the Regional Haze Rule (40 CFR § 51.308). States are responsible for developing a Regional Haze SIP that addresses regional haze in each Class I area located within the state and in each Class I area located outside the state which may be affected by emissions from sources within the state. The Regional Haze SIP is required to identify existing facilities that cause or contribute to visibility impairment; analyze, identify, and apply federally-enforceable control strategies for those sources; and periodically demonstrate reasonable progress toward reaching visibility goals. States are also responsible for periodic comprehensive updates to their Regional Haze SIP that address these same topics. Minnesota's Round 2 Regional Haze SIP must be submitted to the U.S. Environmental Protection Agency (U.S. EPA) by July 31, 2021.

Minnesota has two Class I areas within its borders, the Boundary Waters Canoe Area Wilderness (BWCA) and Voyageurs National Park (Voyageurs). Other nearby Class I areas include Isle Royale National Park in Michigan. Therefore, Minnesota must prepare a Regional Haze SIP that identifies sources that cause or contribute to visibility impairment in these areas. To meet the core requirements for regional haze for these areas, Minnesota must submit a SIP that contains the plan elements and supporting documentation for all required analyses identified in 40 CFR § 51.308(f).

In the first planning period (Round 1), the focus of the Regional Haze Rule was on establishing Best Available Retrofit Technology (BART) for certain older sources and reasonable progress towards national visibility goals. In Round 2, there are no BART requirements; therefore, the focus is on making reasonable progress. The U.S. Environmental Protection agency has defined the methodology that states must use to determine what measures are necessary to make reasonable progress in 40 CFR § 51.308(f)(2). At minimum, the reasonable progress analysis must use the four factors identified in 40 CFR § 51.308(f)(2)(i) to evaluate and determine the emission reduction measures necessary to make reasonable progress. The four factors are:

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

Data from the IMPROVE monitoring sites at BWCA and Voyageurs indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X).

You are receiving this letter because your facility was identified as a significant source of NO_X and SO_2 and is located close enough to the BWCA or Voyageurs to potentially cause or contribute to visibility impairment in these Class I areas. Therefore, the MPCA requests that you prepare a “Four Factor Analysis” for the following emission units:

1. Recovery Furnace (EQUI 9 / EU 320) that addresses emissions of NO_X
2. Boiler #1 (EQUI 15 / EU 420) that addresses emissions of NO_X
3. Boiler #2 (EQUI 16 / EU 430) that addresses emissions of NO_X and SO_2

The analysis should be prepared using the U.S. Environmental Protection Agency guidance[1] that provides recommendations for how each of the factors should be determined.

Preparation of the comprehensive update to Minnesota’s Regional Haze SIP will require extensive planning and review of sources in Minnesota. The MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to prepare the Regional Haze SIP. The MPCA expects air quality modeling of potential regional emissions reductions will be conducted beginning in spring 2020. I appreciate your attention to this matter and request that you **submit the Four Factor Analysis by July 31, 2020**.

If you have any questions regarding this matter, or would like to request a meeting to further discuss the contents of this letter, please contact me by phone at 651-757-2653 or by email at Hassan.Bouchareb@state.mn.us.

Sincerely,

Hassan Bouchareb

This document has been electronically signed.

Hassan M. Bouchareb
Engineer
Environmental Analysis and Outcomes Division

Cc: Kara Huziak, Boise White Paper LLC
Deepa de Alwis, MPCA
Cory Boeck, MPCA
Frank Kohlasch, MPCA
Agency Interest ID 443

Address questions and submittals requested above to:

Hassan M. Bouchareb
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155-4194
(651) 757-2653
Hassan.Bouchareb@state.mn.us

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[1] **U.S. Environmental Protection Agency.** *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 20, 2019, https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

PACKAGING CORPORATION OF AMERICA

May 8, 2020

Hassan M. Bouchareb
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155-4194

Re: Request for Information – Regional Haze Rule, Reasonable Progress, Four-Factor Analysis

Dear Mr. Bouchareb:

This letter is in response to your January 29, 2020, request for information (RFI) to Boise White Paper LLC (Boise) regarding the Regional Haze Rule (RHR). The RFI requested that Boise submit a "four-factor analysis" of control equipment for three emission units at our International Falls facility. The analysis would be used by the Minnesota Pollution Control Agency (MPCA) to develop a comprehensive update to Minnesota's Regional Haze State Implementation Plan (SIP) as required by the RHR (40 CFR 51.308). The RFI stated that the analysis should be prepared following guidance[1] provided by the U. S. Environmental Protection Agency (EPA).

EPA's guidance recognizes that the states have flexibility in deciding which sources must conduct a four-factor analysis. For example, the guidance states that it "*may be reasonable for a state not to select an effectively controlled source*"[2] and that, for such sources, a state should explain "*why it is reasonable to assume for the purposes of efficiency and prioritization that a full four-factor analysis would likely result in the conclusion that no further controls are necessary.*"[3]

This letter requests that MPCA withdraw the RFI for the Recovery Furnace (EQUI 9 / EU 320) and Boiler #2 (EQUI 15 / EU 420) because these sources are already "effectively controlled" as defined in EPA's guidance[4]. The following supporting rationale explains why this determination is consistent with MPCA's requirement to make reasonable progress.

1 Background

The MPCA is required to develop and implement air quality protection plans to reduce pollution that causes haze at national parks and wilderness areas, known as Class I areas. The RHR requirements are found in 40 CFR 51.308. The state of Minnesota includes two Class I areas: Boundary Waters Canoe Area Wilderness (BWCAW) and Voyageurs National Park (Voyageurs). In addition, emissions from sources in Minnesota could potentially impact Class I areas in nearby states—namely, Isle Royale National Park (Isle Royale) in Michigan. Although Michigan is responsible for evaluating haze at Isle Royale, it must consult with surrounding states, including Minnesota, on potential cross-state haze pollution impacts.

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[1] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019.
[2] Ibid, Page 22.
[3] Ibid, Page 23
[4] Ibid, Page 22.

The goal of the RHR is to return the Class I areas to natural visibility conditions by 2064. To that end, the RHR requires states to develop a state implementation plan (SIP) and to provide comprehensive updates every 10 years. MPCA submitted its Regional Haze SIP in December 2009, updated it in May 2012, and must submit a comprehensive update by July 31, 2021, to address reasonable progress in the second implementation period, 2018-2028. Progress is tracked by the EPA and the MPCA based on the IMPROVE (Interagency Monitoring of Protected Visual Environments) monitoring sites at the BWCAW (BOWA1), Voyageurs (VOYA2) and Isle Royale (ISLE1).

Each SIP revision is required to address several elements, including:

- Calculations of baseline, current, and natural visibility conditions; progress to date; and the uniform rate of progress (40 CFR 51.308(f)(1))
- Long-term strategy for regional haze (40 CFR 51.308(f)(2))
- Reasonable progress goals (40 CFR 51.308(f)(3))
- Monitoring strategy and other implementation plan requirements (40 CFR 51.308(f)(6))

On January 29, 2020, MPCA sent an RFI to Boise which stated that our facility was identified as a significant source of NO_X and SO_2 and is located close enough to the BWCAW or Voyageurs to potentially cause or contribute to visibility impairment in these Class I areas. Therefore, the MPCA requested that we submit a "four-factor analysis"[5] by July 31, 2020, for the emission units and applicable pollutants identified in Table 1.

Table 1: Identified Emission Units

Unit	Unit ID	Applicable Pollutants
Recovery Furnace	EQUI 9 / EU 320	NO_X
Boiler #1	EQUI 15 / EU 420	NO_X
Boiler #2	EQUI 16 / EU 430	NO_X, SO_2

The RFI stated that the "*analysis should be prepared using the U.S. Environmental Protection Agency guidance*[6] *that provides recommendations for how each of the factors should be determined.*" The results of the four-factor analysis would be incorporated into the long-term strategy which must "*include the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress.*"[7]

The reasonable progress goals are determined based on several criteria, including an evaluation of the "*rate of progress needed to attain natural visibility conditions by the year 2064.... In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction measures needed to achieve it for the period covered by the implementation plan.*"[8]

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[5] The four factors are presented in 40 CFR 51.308(f)(2)(i): cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts of compliance and remaining useful life of the source.

[6] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[7] 40 CFR 51.308(f)(3)

[8] 40 CFR 51.308(d)(1)(i)(B)

2 Current Visibility in BWCAW, Voyageurs, and Isle Royale

The data from the IMPROVE monitoring network for BWCAW, Voyageurs, and Isle Royale are available on MPCA's website[9]. As shown in figures 1 through 3, the visibility at each Class I area has been improving since 2009 and is already below the 2028 uniform rate of progress (URP)[10]. The observed visibility improvement could be attributed to emission reductions from regulated stationary sources due to a variety of reasons, including:

- installation of best available retrofit technology (BART) during the first RHR implementation period,
- emission reductions from a variety of industries, including the pulp and paper sources, due to updated rules and regulations, and
- transition of power generation systems from coal to natural gas and renewables (wind and solar).

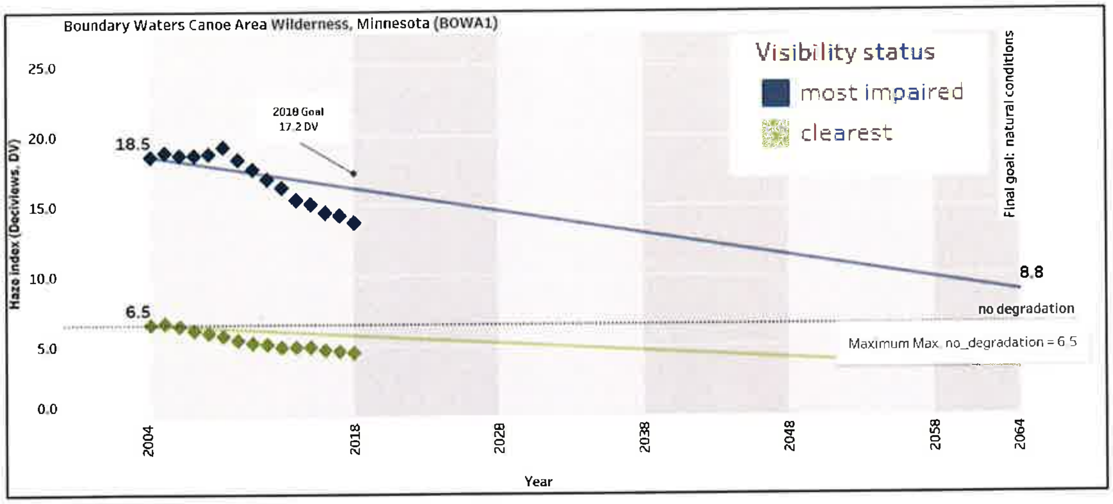

Figure 1: BWCAW Current Visibility Conditions

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[9] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

[10] The URP is determined based on the slope of the line from baseline conditions (2000-2004) to the natural visibility conditions in 2064

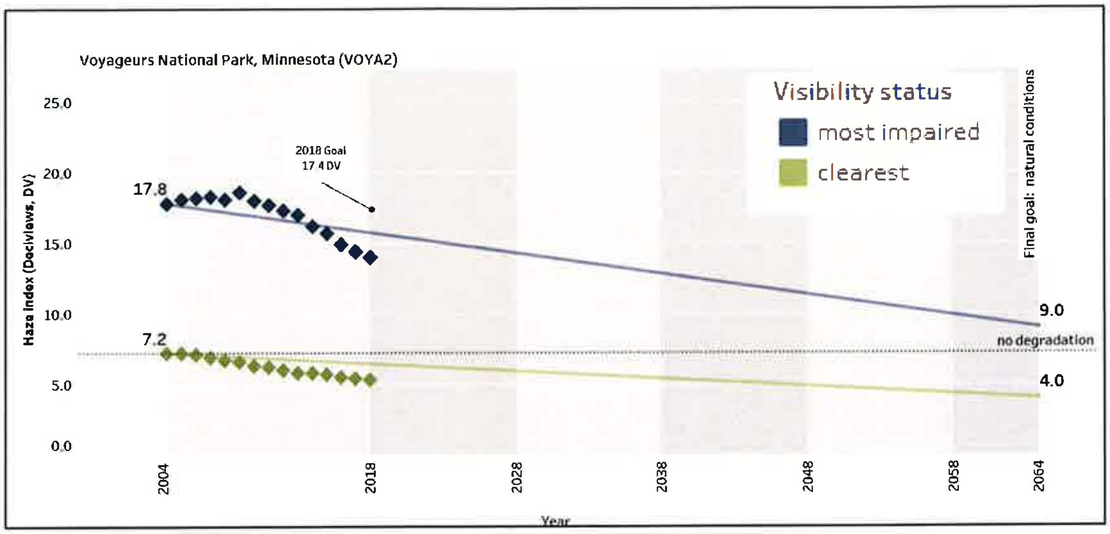

Figure 2: Voyageurs Current Visibility Conditions

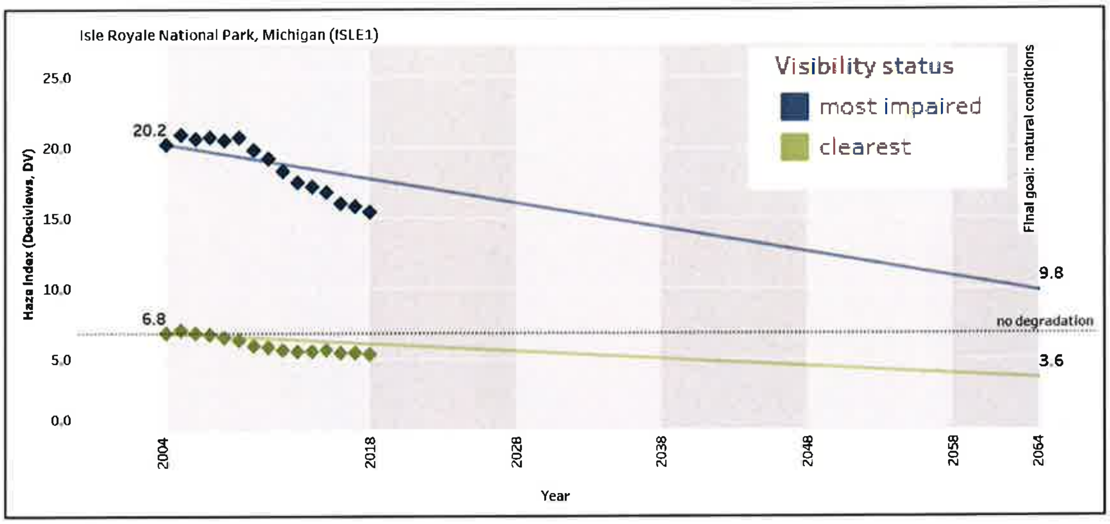

Figure 3: Isle Royale Current Visibility Conditions

Some of these emission reductions have recently occurred but are not fully reflected in the 5-year average monitoring data presented in Figures 1 through 3. For example, Minnesota Power retired two coal-fired boilers at the Boswell Energy Center in Cohasset at the end of 2018. In addition, the compliance schedule is still in progress for the NO_X emission reductions required by the Taconite Federal Implementation Plan (FIP) Establishing BART for Taconite Plants (40 CFR 52.1235). Furthermore, there are others emission reduction projects that are scheduled to occur in Minnesota prior to 2028, the end of the second RHR implementation period (e.g., Xcel Energy boiler retirements as detailed in their Upper Midwest Integrated Resource Plan, 2020-2034). These emission reductions will further improve the visibility in the Class I areas and further reduce visibility trends below the URP.

3 EPA Guidance for State Implementation Plans

MPCA's January 29, 2020, RFI stated that the four-factor analysis should follow EPA's guidance[11] that provides recommendations for how each of the factors should be determined. Additionally, EPA also provides states guidance on selecting sources which must conduct a four-factor analysis.

The guidance says that the state will determine which emission control measures are necessary to make reasonable progress in the affected Class I areas[12]. However, as discussed in Section 2, the current sustained progress towards visibility goals in BWCAW, Voyageurs, and Isle Royale is such that the MPCA may determine that the current reduction trajectory of emission reductions during the second implementation period represents reasonable progress. The MPCA would be warranted to further consider the flexibility allowed in the RHR to "*reasonably select a set of sources for an analysis of control measures.*"[13] The monitoring information will help MPCA "*explain why the decision is consistent with the requirement to make reasonable progress.*"[14]

4 EPA Guidance for Effectively Controlled Sources

EPA guidance states that it "may be reasonable for a state not to select an effectively controlled source"[15] for the four-factor analysis with the rationale that "*it is reasonable to assume for the purposes of efficiency and prioritization that a full four-factor analysis would likely result in the conclusion that no further controls necessary.*"[16] EPA identified potential scenarios that "*EPA believes it may be reasonable for a state not to select a particular source for further analysis.*" However, EPA clarified that the associated scenarios are not a comprehensive list but are merely to illustrate examples for the state to consider.

One of the "effectively controlled" scenarios is for sources that went through a best available control technology (BACT) review with a construction permit issued on or after July 31, 2013.[17] EPA notes that the BACT control equipment review methodologies are "*similar to, if not more stringent than, the four statutory factors for reasonable progress.*" As presented below, an extension of the BACT review scenario is for sources that have existing permit limits, independent of the statutory basis (e.g., air dispersion modeling, PSD avoidance limit, etc.), which are consistent or sufficiently similar to recent BACT determinations for similar sources. Because the limits are similar to BACT, this extension is consistent with EPA's conclusion that a four-factor analysis "*would likely result in the conclusion that no further controls are necessary.*"

4.1 Recovery Furnace (EQUI 9 / EU 320)

The RFI requested a four-factor analysis for NO_X emissions from the Recovery Furnace which is a combustion unit that burns black liquor solids (BLS) from the Kraft pulping process to recover spent cooking chemicals. The combustion process generates heat which is recovered by steam generation. The combustion process results in NO_X and other emissions.

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[11] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[12] Ibid, Page 9.

[13] Ibid.

[14] Ibid, Page 23.

[15] Ibid, Page 22.

[16] Ibid, Page 23.

[17] Ibid.

The Recovery Furnace has not undergone a NO_X BACT review since July 31, 2013, so this unit does not directly meet this scenario. However, the current NO_X limit[18] (100 lb/hr per 30-day rolling average, which is equivalent to 80 ppm at 8% oxygen (O_2)) was compared to recent determinations in EPA's RBLC database (Attachment A); the current limit is lower than NO_X limits from recent BACT determinations (e.g., 85 ppm at 8% O_2[19], 120 ppm at 8% O_2[20]).

Because the current NO_X emission limit is consistent with recent BACT determinations and BACT control equipment reviews are "*similar to if not more stringent than*" the four-factor analysis methodology, it is unlikely that additional controls would be available to further reduce NOx emissions. Therefore, this unit is sufficiently similar BACT scenario and MPCA can justify that a four-factor analysis need not be completed.

4.2 Boiler #2 (EQUI 16 / EU 430)

The RFI requested a four-factor analysis for NO_X and SO_2 emissions Boiler #2 which is an industrial boiler that is permitted to burn the following fuels: [21]

- Biomass (commonly referred to as "hog fuel")
- Waste Water Treatment Plant Sludge (biomass)
- Natural Gas
- Non-Condensable Gas (NCG)

The associated combustion results in NO_X and SO_2 emissions, among other emissions.

NO_X: Boiler #2's current NO_X limit[22] (100.2 lb/hr, which is equivalent to 0.25 lb/MMBtu at the maximum firing rate) was compared to recent determinations in EPA's RBLC database (Attachment B) and the limit is similar to and consistent with NO_X limits from recent BACT determinations (e.g., two determinations[23,24] with 0.3 lb/MMBtu limits).

Because the current NO_X emission limit is similar to recent BACT determinations and BACT control equipment reviews are "*similar to if not more stringent than*" the four-factor analysis methodology, it is unlikely that additional controls would be available to further reduce emissions. Therefore, this unit is a sufficiently similar BACT scenario and MPCA can justify that a four-factor analysis need not be completed.

SO_2: When considering the SO2 emissions from Boiler #2, it is important to note:

- The primary fuel is hog fuel, a biomass which is primarily bark from the facility de-barking process. This fuel is inherently low in sulfur.

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[18] Title V Operating Permit (TVOP) Condition 5.13.7

[19] 2019 BACT determination for Sun Bio Materials Company (AR-0161)

[20] 2015 BACT determination for Rocktenn CP, LLC (AL-0302)

[21] Permit 07100002-014 Condition 5.17.14 limits fuel burned to "bark, wood refuse, wastewater treatment sludge, paper, and natural gas. Non-condensable gas (NCG) is also oxidized in Boiler #2."

[22] TVOP Condition 5.17.7

[23] 2010 BACT determination for Boise White Paper (AL-0250)

[24] 2014 BACT determination for Abengoa Bioenergy Biomass of Kansas (KS-0034)

- Natural gas is a supplemental fuel and is also a low-sulfur fuel.
- Most of the SO_2 emissions from the boiler are a direct result of Non-Condensable Gas (NCG) combustion. However, Boiler #2 is the secondary NCG combustion source[25] and is only utilized when the primary NCG combustion source (Lime Kiln (EQUI 13 / EU 340)) is unavailable; Boiler #1 (EQUI 15 / EU 420) is the tertiary NCG combustion device[26].
- Boiler #2 has an SO_2 emission limit (9.4 lb/hr as a 12-hr rolling average, equivalent to 0.024 lb/MMBtu at the maximum firing rate) which applies when NCG is not being combusted.[27]
- Boiler #1 and Boiler #2 have a combined SO_2 emission limit (115 tons per rolling 12-month period) which applies when burning NCG in either of the backup combustion sources.[28]
- Maintaining the ability to combust the NCG in the backup combustion sources is part of the overall regulatory compliance strategy for limiting emissions of hazardous air pollutants because 40 CFR Part 63 Subpart S (National Emission Standards for Hazardous Air Pollutants from the Pulp and Paper Industry) limits the amount of time that NCG can be vented to the atmosphere without combustion.
- Additionally, maintaining the ability to combust NCG in the backup combustion sources is an engineered control to maintain the continued safe operation of the Kraft pulping equipment and process.

Boiler #2's current SO_2 limit, which applies when NCG is not being combusted (9.4 lb/hr as a 12-hr rolling average, which is equivalent to 0.024 lb/MMBtu at the maximum firing rate)[29], was compared to recent determinations in EPA's RBLC database (Attachment C). The limit is similar to and consistent with SO_2 limits from recent BACT determinations for similar sources (e.g., 0.025 lb/MMBtu[30], 0.21 lb/MMBtu[31]).

The TVOP limits the SO_2 emissions from the backup NCG combustion sources (Boiler #1 and Boiler 2) to 115 tons per rolling 12-month period.[32] As stated above, maintaining the ability to combust the NCG in the backup combustion sources is part of the overall regulatory compliance strategy for limiting emissions of hazardous air pollutants as required by 40 CFR Part 63 Subpart S. Boise works diligently to maintain the availability of the primary NCG combustion source (Lime Kiln) which limits the actual emissions from the facility. For example, the maximum annual SO_2 emissions from Boiler #2 in the past five years was 35.4 tons which resulted from 436 hours (18.2 days) of NCG combustion. Although the actual emissions provide for a large margin of compliance, Boise could not take a more stringent limit because the existing limit could be necessary if an unanticipated downtime or failure of the primary combustion source were to occur.

Regarding the installation of SO_2 controls on Boiler #2 for the NCG combustion scenario, it is unlikely that any controls would be cost effective. This conclusion is based on designing the SO_2 controls to treat the full volume of Boiler #2 flue gas (i.e., a large annualized capital expenditure) but only operating the equipment when NCG is being combusted (e.g., the maximum SO_2 emissions from Boiler #2 in the past five years resulted from 18.2 days of NCG combustion). The annualized cost will be

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[25] TVOP Condition 5.3.3
[26] Ibid.
[27] TVOP Condition 5.17.6
[28] TVOP Condition 5.3.6
[29] TVOP Condition 5.17.6
[30] 2019 BACT determination for Sun Bio Materials Company (AR-0161)
[31] 2014 BACT determination for Abengoa Bioenergy Biomass of Kansas (KS-0034)
[32] TVOP Condition 5.3.6

high but the low utilization of the control equipment (< 1% of operating time) will not result in large actual emission reductions and the cost would therefore not be cost-effective.

The SO_2 emission limit when NCG is not being combusted is similar to recent BACT determinations and BACT control equipment reviews are "*similar to if not more stringent than*" the four-factor analysis methodology, it is unlikely that additional controls would be available to further reduce emissions. In addition, the SO_2 emission limit when NCG is being burned is necessary for the backup combustion sources to ensure control of HAP emissions but the installation of control equipment to operate only when combustion NCG would not be cost effective. Therefore, the MPCA can justify that a four-factor analysis need not be completed.

5 Conclusion

As described in Section 2, the current visibility in the nearby Class I areas is already below the 2028 URP glidepath, so MPCA may determine that the RHR reasonable progress goal for the SIP revision due in 2021 is being achieved. Furthermore, as described in Section 4, there is sufficient well-documented justification to consider the Recovery Furnace and Boiler #2 as "effectively controlled" sources. Thus, it "*may be reasonable for a state not to select an effectively controlled source*" to conduct a four-factor analysis because "*there will be only a low likelihood of a significant technological advancement that could provide further reasonable emission reductions.*"[33] Therefore, Boise requests that your RFI dated January 29, 2020, be withdrawn for the Recovery Furnace and Boiler #2. We will continue to proceed with a four-factor analysis for Boiler #1 as directed in the RFI dated January 29, 2020.

We are available at your convenience to discuss this request in detail. Please advise if a telephone conference is desired. You may contact Kara Huziak at karahuziak@boisepaper.com with questions or to request a meeting.

Thank you for considering our request.

Sincerely,

Mike Wagner

Mike Wagner
Mill Manager

Attachments:

A. RBLC Summary: NO_X from Recovery Furnaces
B. RLBC Summary: NO_X from Hog Fuel Boilers
C. RBLC Summary: SO_2 from Hog Fuel Boilers

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[33] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, Page 23.

Boise White Paper LLC
Regional Haze "Effectively Controlled" Source Scenario Comparison Analysis
Attachment A: Recovery Furnace NOx RBLC Search

Pollutant Name: NOx

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
AL-0266	GEORGIA PACIFIC BREWTON LLC	GEORGIA PACIFIC LLC	AL	502-0001-X044	322130	06/11/2014 ACT	Kraft Pulp & Paper mdu	No.4 Recovery & Smelt Tank	Black Liquor	1355	MMBTU/ hr	Nitrogen Oxides (NOx)	Staged air combustion	90	PPM@8%O2	3HRS AVG	BACT-PSD	221	LB/H	3HRS AVG	0		
AL-0266	GEORGIA PACIFIC BREWTON LLC	GEORGIA PACIFIC LLC	AL	502-0001-X044	322130	06/11/2014 ACT	Kraft Pulp & Paper mdu	No. 4 REC & Smelt	Natural Gas	1355	mmbtu	Nitrogen Oxides (NOx)	Gas Combustion	0.2	LB/MMBTU	3 HRS AVG	BACT-PSD	145.12	LB/H	3 HRS AVG	0		
AL-0274	BOISE WHITE PAPER, LLC	BOISE WHITE PAPER, LLC	AL	102-0001-X011	322121	02/04/2015 ACT	Paper mill	Recovery Furnace - Non-Direct Contact with Dry -	Black Liquor Solids (BLS)	2.88	million lbs. of BLS	Nitrogen Oxides (NOx)		90	PPMDV	@8% O2	BACT-PSD	105.8	LB/H	3-HR. ROLLING	0		
AL-0302	ROCKTENN STEVENSON	ROCKTENN CP, LLC	AL	705-0014-X014	322130	04/29/2015 ACT	Pulp & Paper Mill	Recovery Boiler	Black Liquid	58334	LB/LB BL	Nitrogen Oxides (NOx)		120	PPM@8%O2	30 DAYS AVG	BACT-PSD	72.92	LB/H	3 HRS AVG	0		
AL-0320	GP BREWTON	GEORGIA-PACIFIC BREWTON LLC	AL	502-0001-X044	322130	01/03/2018 ACT		No. 4 Recovery Furnace	Black Liqour	1355	MMBtu/hr	Nitrogen Oxides (NOx)		90	PPMV @8% O2		BACT-PSD	221.9	LB/HR	3 HR	0		
AR-0156	GREEN BAY PACKAGING - ARKANSAS KRAFT DIVISION	GREEN BAY PACKAGING - ARKANSAS KRAFT DIVISION	AR	0224-AOP-R21	322130	02/08/2019 ACT	paperboard mill	Recovery Boiler	black liquor solids	401400	T/YR	Nitrogen Oxides (NOx)		80	LB/H		OTHER CASE-BY-CASE	313.1	T/YR		0		
*AR-0161	SUN BIO MATERIAL COMPANY	SUN BIO MATERIAL COMPANY	AR	2384-AOP-R0	322110	09/23/2019 ACT	A kraft paper mill designed with one high yield Kraft softwood Fiberline and two linerboard machiens. The plant is initially sized to support an approximate, nominal linerboard production capacity of 4,400 machine dry tons per day at varying base weights.	Recovery Boiler	Black Liquor Solids	2900	MMBtu/hr	Nitrogen Oxides (NOx)	Quaternary Air/Staged Combustion	85	PPMVD @ 8% O2	3 1-HOUR TESTS	BACT-PSD	0			0		
*AR-0161	SUN BIO MATERIAL COMPANY	SUN BIO MATERIAL COMPANY	AR	2384-AOP-R0	322110	09/23/2019 ACT	A kraft paper mill designed with one high yield Kraft softwood Fiberline and two linerboard machiens. The plant is initially sized to support an approximate, nominal linerboard production capacity of 4,400 machine dry tons per day at varying base weights.	Lime Kiln	Natural Gas	225	MMBtu/hr	Nitrogen Oxides (NOx)	Good Combustion Practices	180	PPMVD @ 10% O2	3 1-HOUR TESTS	BACT-PSD	0			0		
*AR-0161	SUN BIO MATERIAL COMPANY	SUN BIO MATERIAL COMPANY	AR	2384-AOP-R0	322110	09/23/2019 ACT	A kraft paper mill designed with one high yield Kraft softwood Fiberline and two linerboard machiens. The plant is initially sized to support an approximate, nominal linerboard production capacity of 4,400 machine dry tons per day at varying base weights.	Power Boiler	Biomass	1200	MMBtu/hr	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	0.06	LB/MMBTU	3-HOUR	BACT-PSD	0			0		

Boise White Paper LLC
Regional Haze "Effectively Controlled" Source Scenario Comparison Analysis
Attachment B: Hog Fuel Boiler NOx RBLC Search

Pollutant Name: NOx

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
AL-0250	BOISE WHITE PAPER	BOISE WHITE PAPER, LLC	AL	102-0001	322121	03/23/2010 ACT		COMBINATION BOILER	WOOD	435	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNERS	0.3	LB/MMBTU	3 H	BACT-PSD	130.5	LB/H	3 H	0		
*AR-0161	SUN BIO MATERIAL COMPANY	SUN BIO MATERIAL COMPANY	AR	2384-AOP-R0	322110	09/23/2019 ACT	A kraft paper mill designed with one high yield Kraft softwood Fiberline and two linerboard machiens. The plant is initially sized to support an approximate, nominal linerboard production capacity of 4,400 machine dry tons per day at varying base weights.	Power Boiler	Biomass	1200	MMBtu/hr	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	0.06	LB/MMBTU	3-HOUR	BACT-PSD	0			0		
CA-1203	SIERRA PACIFIC INDUSTRIES-LOYALTON	SIERRA PACIFIC INDUSTRIES	CA	SAC 87-01-A	221119	08/30/2010 ACT	20 MW COGENERATION POWER PLANT	RILEY SPREADER STOKER BOILER - Transient Period (see notes)	WOOD	335.7	MMBTU/H	Nitrogen Oxides (NOx)	SELECTIVE NON-CATALYTIC REDUCTION (SNCR)	102	PPM	@12% CO2, 8-HR ROLLING AVG	BACT-PSD	65	LB/H	8-HR ROLLING AVG	0		
CA-1203	SIERRA PACIFIC INDUSTRIES-LOYALTON	SIERRA PACIFIC INDUSTRIES	CA	SAC 87-01-A	221119	08/30/2010 ACT	20 MW COGENERATION POWER PLANT	RILEY SPREADER STOKER BOILER	WOOD	335.7	MMBTU/H	Nitrogen Oxides (NOx)	SELECTIVE NON-CATALYTIC REDUCTION (SNCR)	80	PPM	@12% CO2, 8-HR ROLLING AVG	BACT-PSD	50.75	LB/H	8-HR ROLLING AVG	0		
CA-1225	SIERRA PACIFIC INDUSTRIES-ANDERSON DIVISION	SIERRA PACIFIC INDUSTRIES	CA	SAC 12-01	321113	04/25/2014 ACT	31 MW COGENERATION AND LUMBER MANUFACTURING FACILITY	STOKER BOILER (NORMAL OPERATION)	BIOMASS	468	MMBTU/H	Nitrogen Oxides (NOx)	SNCR	0.13	LB/MMBTU	12-MONTH ROLLING BASIS	BACT-PSD	0.15	LB/MMBTU	3-HOUR BLOCK AVERAGE	0		
CA-1225	SIERRA PACIFIC INDUSTRIES-ANDERSON DIVISION	SIERRA PACIFIC INDUSTRIES	CA	SAC 12-01	321113	04/25/2014 ACT	31 MW COGENERATION AND LUMBER MANUFACTURING FACILITY	STOKER BOILER (STARTUP & SHUTDOWN PERIODS)	BIOMASS	468	MMBTU/H	Nitrogen Oxides (NOx)	SNCR	70.2	LB/H	8-HR AVG (STARTUP PERIODS)	BACT-PSD	70.2	LB/H	8-HR AVG (SHUTDOWN PERIODS)	0		
CT-0156	MONTVILLE POWER LLC	NRG ENERGY	CT	107-0056	221119	04/06/2010 ACT	43 MW STOKER FIRED BIOMASS; 82 MW TANGENTIALLY FIRED NATURAL GAS/ULS DISTILLATE UTILITY BOILER (7% ANNUAL CAPACITY FACTOR)	42 MW Biomass utility boiler	Clean wood	600	MMBTU/H	Nitrogen Oxides (NOx)	Regenerative SCR	0.06	LB/MMBTU	24 HR BLOCK	LAER	0			0		
CT-0162	PLAINFIELD RENEWABLE ENERGY, LLC	PLAINFIELD RENEWABLE ENERGY, LLC	CT	145-0049	221119	12/29/2010 ACT	37.5 MW Biomass Power Plant	Fluidized Bed Gasification	Wood	523.1	MMBtu/hr	Nitrogen Oxides (NOx)	SNCR	0.075	LB/MMBTU		LAER	45.3	PPMVD @7% O2	24 HR BLOCK	0		
GA-0141	WARREN COUNTY BIOMASS ENERGY FACILITY	OGETHORPE POWER CORPERATION	GA	4911-301-0016-P-01-0	221119	12/17/2010 ACT	The proposed project will include: a bubbling fluidized bed boiler with a maximum total heat input capacity of 1,399 MMBTU/H, 2 fire water pump emergency engines; a raw material handling & storage area; a sorbent storage silo; a boiler bed sand silo, a sand day	Boiler, Biomass Wood	Biomass wood	100	MW	Nitrogen Oxides (NOx)	Selective non-catalytic reduction system (SNCR)	0.1	LB/MMBTU	30 D ROLLING AV / CONDITION 2.9	BACT-PSD	648	TONS	12 MONTH ROLLING TOTAL / CONDITION 2.18	0		
*KS-0034	ABENGOA BIOENERGY BIOMASS OF KANSAS (ABBK)	ABENGOA BIOENERGY BIOMASS OF KANSAS (ABBK)	KS	C-11396	325193	05/27/2014 ACT	Abengoa Bioenergy Biomass of Kansas (ABBK) intends to install and operate a biomass-to-ethanol and biomass-to-energy production facility near Hugoton, Kansas.	biomass to energy cogeneration bioler	different types of biomass	500	MMBtu/hr	Nitrogen Oxides (NOx)	Selective Catalytic Reduction System (SCR) and an over-fire system (OFA)	0.3	LB/MMBTU	30-DAY ROLLING, INCLUDES SSM	BACT-PSD	157.5	LB/HR	1-HR AVE, INCLUDES SSM	0		
ME-0037	VERSO BUCKSPORT LLC	VERSO BUCKSPORT LLC	ME	A-22-77-4-A	322121	11/29/2010 ACT	Existing pulp (groundwood and thermomechanical) and paper making facility.	Biomass Boiler 8	Biomass	814	MMBTU/H	Nitrogen Oxides (NOx)	SNCR	0.15	LB/MMBTU	30 DAY ROLLING	BACT-PSD	244.2	LB/H		0		

Boise White Paper LLC
Regional Haze "Effectively Controlled" Source Scenario Comparison Analysis
Attachment C: Hog Fuel Boiler SO2 RBLC Search

Pollutant Name: SO2

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
*AR-0161	SUN BIO MATERIAL COMPANY	SUN BIO MATERIAL COMPANY	AR	2384-AOP-R0	322110	09/23/2019 ACT	A kraft paper mill designed with one high yield Kraft softwood Fiberline and two linerboard machiens. The plant is initially sized to support an approximate, nominal linerboard production capacity of 4,400 machine dry tons per day at varying base weights.	Power Boiler	Biomass	1200	MMBtu/hr	Sulfur Dioxide (SO2)	FGD/Dry Sorbent Injection	0.025	LB/MMBTU	3 1-HOUR TESTS	BACT-PSD	0			0		
CT-0156	MONTVILLE POWER LLC	NRG ENERGY	CT	107-0056	221119	04/06/2010 ACT	43 MW STOKER FIRED BIOMASS; 82 MW TANGENTIALLY FIRED NATURAL GAS/ULS DISTILLATE UTILITY BOILER (7% ANNUAL CAPACITY FACTOR)	42 MW Biomass utility boiler	Clean wood	600	MMBTU/H	Sulfur Oxides (SOx)	Low sulfur fuels	0.025	LB/MMBTU	3 HR BLOCK	BACT-PSD	0			0		
CT-0162	PLAINFIELD RENEWABLE ENERGY, LLC	PLAINFIELD RENEWABLE ENERGY, LLC	CT	145-0049	221119	12/29/2010 ACT	37.5 MW Biomass Power Plant	Fluidized Bed Gasification	Wood	523.1	MMBtu/hr	Sulfur Dioxide (SO2)	Spray Dryer, Bed Injection	0.035	LB/MMBTU		OTHER CASE-BY-CASE	15.4	PPMVD @7% O2	3 HR BLOCK	0		
GA-0141	WARREN COUNTY BIOMASS ENERGY FACILITY	OGETHORPE POWER CORPERATION	GA	4911-301-0016-P-01-0	221119	12/17/2010 ACT	The proposed project will include: a bubbling fluidized bed boiler with a maximum total heat input capacity of 1,399 MMBTU/H, 2 fire water pump emergency engines; a raw material handling & storage area; a sorbent storage silo; a boiler bed sand silo, a sand day	Boiler, Biomass Wood	Biomass wood	100	MW	Sulfur Oxides (SOx)	Dust sorbent injection system	0.01	LB/MMBTU	30 D ROLLING AV / CONDITION 2.12	BACT-PSD	56	TONS	12 MONTH ROLLING TOTAL / CONDITION 2.20	0		
*KS-0034	ABENGOA BIOENERGY BIOMASS OF KANSAS (ABBK)	ABENGOA BIOENERGY BIOMASS OF KANSAS (ABBK)	KS	C-11396	325193	05/27/2014 ACT	Abengoa Bioenergy Biomass of Kansas (ABBK) intends to install and operate a biomass-to-ethanol and biomass-to-energy production facility near Hugoton, Kansas.	biomass to energy cogeneration bioler	different types of biomass	500	MMBtu/hr	Sulfur Dioxide (SO2)	Injection of sorbent (lime) in combination with a dry flue gas desulfurization (FGD) system	0.21	LB/MMBTU	30-DAY ROLLING, INCLUDES SSM	BACT-PSD	110.25	LB/HR	MAX 1-HR, INCLUDES SS, EXCLUDES MALFUNCT	0		
LA-0249	RED RIVER MILL	INTERNATIONAL PAPER CO	LA	PSD-LA-562(M-4)	322130	05/09/2011 ACT	KRAFT PULP MILL WHICH PRODUCES UNBLEACHED LINERBOARD	NO. 2 HOGGED FUEL BOILER	HOGGED FUEL/BARK	992.43	MMBTU/H	Sulfur Dioxide (SO2)	USE OF LOW SULFUR FUELS	60	LB/H	HOURLY MAXIMUM	BACT-PSD	262.8	T/YR	ANNUAL MAXIMUM	0.06	LB/MMBTU	
ME-0037	VERSO BUCKSPORT LLC	VERSO BUCKSPORT LLC	ME	A-22-77-4-A	322121	11/29/2010 ACT	Existing pulp (groundwood and thermomechanical) and paper making facility.	Biomass Boiler 8	Biomass	814	MMBTU/H	Sulfur Dioxide (SO2)	0.7% sulfur when firing oil	0.8	LB/MMBTU	3-HR AVERAGE	BACT-PSD	651.2	LB/H		0		

Regional Haze Four-Factor Analysis

Boiler #1 (EQUI 15 / EU 420)
Boiler #2 (EQUI 16 / EU 430)
Recovery Furnace (EQUI 9 / EU 320)

Prepared for
Boise White Paper LLC

July 15, 2020

Regional Haze Four-Factor Analysis

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Prepared for
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July 15, 2020

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Regional Haze Four-Factor Analysis

July 15, 2020

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1 Executive Summary

On January 29, 2020 the Minnesota Pollution Control Agency's (MPCA's) submitted a Request for Information (RFI)[1] to Boise Paper LLC (Boise) regarding an analysis of emission reductions to support the development of the State Implementation Plan (SIP) for the Regional Haze Rule (RHR)[2]. The RFI requested that the facility evaluate potential emissions reduction measures for sulfur dioxide (SO_2) and nitrogen oxides (NO_X) for Boiler #2 (EQUI 16 / EU430), Recovery Furnace (EQUI 9 / EU 320), and for NO_X only for Boiler #1 (EQUI 15 / EU 420). The request said that the analysis must address the four statutory factors laid out in 40 CFR 51.308(f)(2)(i) and pursuant to the final U.S. Environmental Protection Agency (EPA) RHR State Implementation Plan (SIP) guidance[3] (2019 SIP Guidance):

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

The 2019 SIP Guidance was reviewed to determine if either Boiler #2 or Recovery Furnace were "effectively controlled" sources. Appendix A.1 demonstrates that Boiler #2 and Recovery Furnace are "effectively controlled" and does not need to conduct a four-factor analysis for those emission units as required in the January 29, 2020 RFI letter. Concurrence of this demonstration was provided by Hassan Bouchareb on May 29, 2020, which is included as in Appendix A.2.

This report evaluates potential NO_X control technologies and feasibility for Boiler #1, as required in the January 29, 2020 RFI. Boise has concluded that new emission controls are not warranted because the cost of compliance of technically feasible retrofit emission control technologies is not cost effective. As such, Boise proposes to maintain the existing NO_X permit limits for Boiler #1 as presented in Table 2-2.

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[1] January 29, 2020 letter from Hassan Bouchareb of MPCA to Boise Paper LLC.

[2] The U.S. Environmental Protection Agency (EPA) also refers to this regulation as the Clean Air Visibility Rule. The regional haze program requirements are promulgated at 40 CFR 51.308. The SIP requirements for this implementation period are specified in §51.308(f).

[3] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003.

2 Introduction

This section discussed the pertinent regulatory background information and a description of the emission sources at Boise which were identified by MPCA for analysis.

2.1 Four-factor Analysis Regulatory Background

The RHR published on July 15, 2005 by the EPA, defines regional haze as "visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources." The RHR requires state regulatory agencies to submit a series of SIPs in ten-year increments to protect visibility in certain national parks and wilderness areas, known as mandatory Federal Class I areas. Each SIP must be developed to make reasonable progress towards the ultimate goal of achieving natural background visibility by 2064. The initial SIPs, which were informed by best available retrofit technology (BART) analyses that were completed on all subject-to-BART sources, were due on December 17, 2007. The second RHR planning period requires development and submittal of updated state SIPs by July 31, 2021.

On January 29, 2020, the MPCA sent an RFI to Boise. The RFI stated that data from the Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring sites at Boundary Waters Canoe Area (BWCA) and Voyageurs National Park (Voyageurs) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of SO_2 and NO_X. In addition, emissions from sources in Minnesota could potentially impact Class I areas in nearby states, namely Isle Royale National Park (Isle Royale) in Michigan. Although Michigan is responsible for evaluating haze in Isle Royale, Michigan must consult with surrounding states, including Minnesota, on potential cross-state haze pollution impacts. As part of the planning process for the SIP development, MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to evaluate regional emission reductions.

The RFIs also stated that the facility was identified as a significant source of NO_X and SO_2 which is located close enough to the BWCA and Voyageurs to potentially cause or contribute to visibility impairment. Therefore, the MPCA requested that Boise submit a "four factors analysis" (herein termed as a four-factor analysis) by July 31, 2020 for the emission units identified in Table 2-1 as part of the State's regional haze reasonable progress.

Table 2-1 Identified Emission Units

Unit	Unit ID	Applicable Pollutants	Effectively Controlled[4]	Four Factor Analysis Required[5]
Boiler #1	EQUI 15 / EU 420	NO_X	Not Applicable	Yes
Boiler #2	EQUI 16 / EU 430	NO_X, SO_2	Yes	No
Recovery Furnace	EQUI 9 / EU 320	NO_X	Yes	No

The MPCA stated that the analysis must consider potential emissions reduction measures by addressing the four statutory factors which are laid out in 40 CFR 51.308(f)(2)(i):

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

The RFI letter to the Boise specified that the "analysis should be prepared using the U.S. Environmental Protection Agency guidance" referring to the final 2019 SIP Guidance.

This report describes the background and analysis for conducting a four-factor analysis for NO_X and SO_2 for the emission units identified in Table 2-1.

2.2 Emission Unit Description

Boise is wholly owned by Packaging Corporation of America (PCA). The facility in International Falls, Minnesota is an integrated kraft pulp and paper mill that produces commodity and specialty paper. The three emission units included in MPCA's RFI are:

- **Boiler #1 (EQUI 15):** This emission unit 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 (EQUI 24) 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.

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[4] See Section 2.3 Boiler #2 and Recovery Furnace: Effective Controls

[5] Four-Factor Analysis applicability for Boiler #2 and Recovery Furnace is included in Appendix A.1

- **Boiler #2 (EQUI 16):** This emission unit 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.

- **Recovery Furnace (EQUI 9):** 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 (H_2SO_4), 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 NO_X controls but does use staged air injection to manage the generation of NO_X.

2.3 Boiler #2 and Recovery Furnace: Effective Controls

The 2019 SIP Guidance states that it "may be reasonable for a state not to select an effectively controlled source"[6] for the four-factor analysis with the rationale that "it is reasonable to assume for the purposes of efficiency and prioritization that a full four-factor analysis would likely result in the conclusion that no further controls necessary."[7] EPA identified potential scenarios that "EPA believes it may be reasonable for a state not to select a particular source for further analysis." However, EPA clarified that the associated scenarios are not a comprehensive list but are merely to illustrate examples for the state to consider.

Boise submitted a letter to MPCA on May 8, 2020 requesting the RFI be withdrawn for Boiler #2 (EQUI 15) and the Recovery Furnace (EQUI 9) because these sources are already "effectively controlled" as defined in the 2019 SIP Guidance. MPCA responded via email on May 29, 2020 and confirmed that these sources are

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[6] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003, Page 22.

[7] Ibid, Page 23.

"effectively controlled," and, therefore, a four-factor analysis is not required. Boise's request letter and MPCA's response email are presented in Appendix A.1 and Appendix A.2, respectively.

2.4 Boiler #1: Permit Limits

Boise's current Title V Operating Permit #01700002-101 limits Boiler #1 NO_X emissions in Conditions 5.13.1-5.14.5. In addition, the emissions of NO_X from this source are also subject to the NO_X Cap Group limits as presented in Conditions 5.2.1-5.2.7. Boiler #1 does not have add-on NO_X controls but the generation of NO_X is managed by good combustion practices and NO_X emissions are measured by a continuous emission monitoring system (CEMS). The numeric emission limits are presented in Table 2-2. It is noteworthy that the individual NO_X emission limit is based on modeling and the NO_X Cap Group limits are based on a visibility impacts analysis. Additionally, the NOx modeling will soon be updated as the air permit Condition 6.1.10 states "The Permittee shall submit a computer dispersion modeling protocol for 1-hour and annual NO2 NAAQS due by 6/6/2021. This protocol will describe the proposed modeling methodology and input data, in accordance with the current version of the MPCA Air Dispersion Modeling Guidance."

Table 2-2 Boiler #1 (EQUI 15) Permit Limits

Pollutant	Condition	Limit	Basis of Limit
NO_X	5.14.3	Nitrogen Dioxide <= 0.20 pounds per million Btu heat input 30-day rolling average.	Title I Condition: 40 CFR 52.21(k) (modeling) & Minn. R. 7007.3000
NO_X	5.2.1	The Permittee shall limit emission of Nitrogen Oxides <= 3.67 tons per day from combustion sources (EQUI 9, EQUI 15, EQUI 16, EQUI 17, and EQUI 18).	Title I Condition: 40 CFR 52.21(o) (visibility) & Minn. R. 7007.3000
NO_X	5.2.3	The Permittee shall limit emissions of Nitrogen Oxides <= 4.18 tons per day. This limit is the total NOx cap for the combustion sources (Boilers #1, #2, #3, #9, and the recovery furnace) (EQUI 15, EQUI 16, EQUI 17, EQUI 18, EQUI 9, respectively) as well as the lime kiln and smelt dissolving tank (EQUI 13 and EQUI 945).	Title I Condition: 40 CFR 52.21(o) (visibility) & Minn. R. 7007.3000

3 Boiler #1: Four-factor Analysis for NO_X

This section identifies baseline emission rates and evaluates the four statutory factors for NO_X emissions from Boiler #1.

3.1 Emission Control Options

The 2019 SIP Guidance states that the "first step in characterizing control measures for a source is the identification of technically feasible control measures for those pollutants that contribute to visibility impairment."[8] However, EPA recognized that a "state must reasonably pick and justify the measures that it will consider, recognizing that there is no statutory or regulatory requirement to consider all technically feasible measures or any particular measures."[9] This section addresses the selection of emission control options for NO_X from Boiler #1.

The following methodology was used to determine which emission control technologies should be considered in the four-factor analysis:

1. Search the RACT/BACT/LAER Clearinghouse (RBLC)[10] for available control technologies with the following search criteria:
    - Similar emission unit type (process name)
    - Similar fuel
    - 10-year look back
2. Eliminate technologies that would not would not apply to the specific emission unit under consideration
3. Advance the remaining technologies for consideration in the four-factor analysis

The RBLC search for natural gas fueled boilers for NO_X is presented in Appendix B and a summary is provided in Table 3-1.

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[8] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003, page 28.

[9] Ibid, Page 29.

[10] RACT/BACT/LAER Clearinghouse (RBLC) as maintained by USEPA (link to RBLC website)

Table 3-1: Natural Gas Power Boiler RBLC Summary – NO_X

RBLC ID	Technology
TN-0162 TN-0164	Selective Catalytic Reduction Low NO_X Burners Flue Gas Recirculation
TX-0811	Selective Catalytic Reduction Low NO_X Burners
TX-0731	Selective Catalytic Reduction
IN-0179 WV-00025	Ultra Low NO_X Burners Flue Gas Recirculation
PA-0306 LA-0314 OH-0363 AK-0083 VA-0325 TX-0712	Ultra Low NO_X Burners
LA-0272 AR-0121 IN-0263 MI-0423 OH-0374	Low NO_X Burners Flue Gas Recirculation
MI-0427	Low NO_X Burners with internal (within the burner) Flue Gas Recirculation
LA-0307 TX-0641 VA-0328 OH-0354 TX-0708	Low NO_X Burners
TX-0576	Good Combustion Practice

Good combustion practices were not considered in the four-factor analysis because these are already implemented through a combination of several efforts, including control strategy, boiler monitoring, and training.

As shown in Table 3-1, the majority of the control technologies presented in the RBLC include LNB or ULNB, with or without FGR. The specific technology selected for these projects was likely dependent on the targeted emission rate. For the purposes of the four-factor analysis, Boise has combined these technologies into a single category titled “LNB/ULNB with or without FGR” and then contacted a vendor to provide a technically feasible solution for the target emission rate (additional detail is provided in Section 3.3).

Based on this information, the technologies that were considered in the four-factor analysis are:

- SCR
- LNB/ULNB with or without FGR

3.2 Baseline Emission Rates

The 2019 SIP Guidance states that the "projected 2028 (or the current) scenario can be a reasonable and convenient choice for use as the baseline control scenario for measuring the incremental effects of potential reasonable progress control measures on emissions, costs, visibility, and other factors."[11] Thus, Boise anticipates flat growth in the paper industry and projects that emissions in 2028 will be equivalent to 2019 actual emissions.

Table 3-2: Projected 2028 NO_X Emissions (tons per year)

Year	Boiler #1
2019 actual emissions	90.9 tons/year
2028 Projected Emissions	90.9 tons/year

3.3 Factor 1 – Cost of Compliance

Boise has completed compliance cost estimates for the selected NO_X emission control measures following EPA's Control Cost Manual as recommended in the 2019 SIP Guidance.[12] The SCR cost estimate were based on spreadsheet templates provided by EPA. The LNB/ULNB cost estimate is based on a vendor cost estimate for which the vendor was asked to provide a technically feasible solution to reduce emissions from the current emission rate (0.131 lb/MMBtu) to 0.050 lb/MMBtu which is the emission limit for Boise's Boiler #3 (EQUI 17) as shown in permit condition 5.16.1. The conceptual design provided by the vendor is LNB with FGR and over-fire air (OFA).

The capital cost estimates were confirmed by Boise's plant engineering staff as reasonable, based on their considerable experience with projects at Boise and their informal conversations with other companies that have completed similar types of projects at other facilities. A more detailed cost estimate is likely to increase the costs for installing and implementing either of the projects. Cost calculation spreadsheets for the NO_X emission control measures are provided in Appendix C.

The cost effectiveness analysis compares the annualized cost of the technology 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.

The resulting cost effectiveness calculations are summarized in Table 3-3.

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[11] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003, page 29.

[12] Ibid, Page 21.

Table 3-3: Boiler #1 NO_X Control Cost Summary, per Unit Basis

Additional Emissions Control Measure	Total Capital Investment ($)	Total Annualized Costs ($/year)	Control Efficiency (%)	Annual Emissions Reduction (tpy)	Pollution Control Cost Effectiveness ($/ton)
SCR	$7,828,245	$970,836	69%	63.1	$15,375
LNB with FGR and OFA	$11,144,531	$1,557,544	62.0%	56.2	$27,707

Based on the information provided in Table 3-3 and in consideration of RHR analyses conducted in other states, the emission control measures were not considered cost effective.

Sections 3.4 through 3.6 provide a screening-level summary of the remaining three factors evaluated for the NO_X emission control measures, understanding that these projects represent substantial capital investments that are not justified on a cost per ton or absolute cost basis.

3.4 Factor 2 – Time Necessary for Compliance

Factor #2 estimates the amount of time needed for full implementation of the different control measures. Typically, the time for compliance considers the time needed to develop and approve the new emissions limit into the SIP by state and federal action, then to implement the project necessary to meet the SIP limit via installation and tie-in of equipment for the emissions control measure.

The technologies would require significant resources and time of at least two to three years design, engineer, procure, and install the equipment. The facility would attempt to complete the construction during a regularly scheduled outage but recognizes that the outage may need to be extended to install all required equipment.

The SIP is scheduled to be submitted in 2021 with the anticipated approval in 2022 (approximately one year after submittal). Once the SIP is approved, the design, engineer, procurement, and installation schedule would begin. This would put the anticipated date of installation in 2024 or 2025.

3.5 Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance

The energy and non-air environmental impacts associated with implementation of the above identified NO_X control measures are summarized below.

- SCR
    - Increased truck and/or train traffic (reagent and catalyst deliveries)
    - Possible ammonia slip (unreacted reagent that is emitted to the atmosphere)
    - Catalyst regeneration
    - Catalyst disposal
    - Electricity consumption (fans and pumps)
- LNB with SCR and OFA
    - Electricity consumption (fans)
    - Possible increase in carbon monoxide (CO) emissions)

3.6 Factor 4 – Remaining Useful Life of the Source

Because Boiler #1 is expected to continue operations for the foreseeable future, the useful life of the individual control measures (assumed 20-year life) was used to calculate emission reductions, amortized costs, and cost effectiveness on a dollar per ton basis.

3.7 Proposed NO_X Controls and Emissions Rates

This four-factor analysis does not support the installation of additional NO_X emission control measures at Boiler #1 beyond those described in Section 2.3. As such, Boise proposes to maintain the existing NO_X permit limits presented in Table 2-2.

Appendices

Appendix A.1

Four-Factor Analysis Applicability

For Boiler #2 and Recovery Furnace

May 8, 2020

Hassan M. Bouchareb
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155-4194

Re: Request for Information – Regional Haze Rule, Reasonable Progress, Four-Factor Analysis

Dear Mr. Bouchareb:

This letter is in response to your January 29, 2020, request for information (RFI) to Boise White Paper LLC (Boise) regarding the Regional Haze Rule (RHR). The RFI requested that Boise submit a "four-factor analysis" of control equipment for three emission units at our International Falls facility. The analysis would be used by the Minnesota Pollution Control Agency (MPCA) to develop a comprehensive update to Minnesota's Regional Haze State Implementation Plan (SIP) as required by the RHR (40 CFR 51.308). The RFI stated that the analysis should be prepared following guidance[1] provided by the U. S. Environmental Protection Agency (EPA).

EPA's guidance recognizes that the states have flexibility in deciding which sources must conduct a four-factor analysis. For example, the guidance states that it "*may be reasonable for a state not to select an effectively controlled source*"[2] and that, for such sources, a state should explain "*why it is reasonable to assume for the purposes of efficiency and prioritization that a full four-factor analysis would likely result in the conclusion that no further controls are necessary.*"[3]

This letter requests that MPCA withdraw the RFI for the Recovery Furnace (EQUI 9 / EU 320) and Boiler #2 (EQUI 15 / EU 420) because these sources are already "effectively controlled" as defined in EPA's guidance[4]. The following supporting rationale explains why this determination is consistent with MPCA's requirement to make reasonable progress.

1 Background

The MPCA is required to develop and implement air quality protection plans to reduce pollution that causes haze at national parks and wilderness areas, known as Class I areas. The RHR requirements are found in 40 CFR 51.308. The state of Minnesota includes two Class I areas: Boundary Waters Canoe Area Wilderness (BWCAW) and Voyageurs National Park (Voyageurs). In addition, emissions from sources in Minnesota could potentially impact Class I areas in nearby states—namely, Isle Royale National Park

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[1] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019.

[2] Ibid, Page 22.

[3] Ibid, Page 23

[4] Ibid, Page 22.

(Isle Royale) in Michigan. Although Michigan is responsible for evaluating haze at Isle Royale, it must consult with surrounding states, including Minnesota, on potential cross-state haze pollution impacts.

The goal of the RHR is to return the Class I areas to natural visibility conditions by 2064. To that end, the RHR requires states to develop a state implementation plan (SIP) and to provide comprehensive updates every 10 years. MPCA submitted its Regional Haze SIP in December 2009, updated it in May 2012, and must submit a comprehensive update by July 31, 2021, to address reasonable progress in the second implementation period, 2018-2028. Progress is tracked by the EPA and the MPCA based on the IMPROVE (Interagency Monitoring of Protected Visual Environments) monitoring sites at the BWCAW (BOWA1), Voyageurs (VOYA2) and Isle Royale (ISLE1).

Each SIP revision is required to address several elements, including:

- Calculations of baseline, current, and natural visibility conditions; progress to date; and the uniform rate of progress (40 CFR 51.308(f)(1))
- Long-term strategy for regional haze (40 CFR 51.308(f)(2))
- Reasonable progress goals (40 CFR 51.308(f)(3))
- Monitoring strategy and other implementation plan requirements (40 CFR 51.308(f)(6))

On January 29, 2020, MPCA sent an RFI to Boise which stated that our facility was identified as a significant source of NO_X and SO_2 and is located close enough to the BWCAW or Voyageurs to potentially cause or contribute to visibility impairment in these Class I areas. Therefore, the MPCA requested that we submit a “four-factor analysis”[5] by July 31, 2020, for the emission units identified in Table 1.

Table 1: Identified Emission Units

Unit	Unit ID	Applicable Pollutants
Recovery Furnace	EQUI 9 / EU 320	NO_X
Boiler #1	EQUI 15 / EU 420	NO_X
Boiler #2	EQUI 16 / EU 430	NO_X, SO_2

The RFI stated that the “*analysis should be prepared using the U.S. Environmental Protection Agency guidance*[6] *that provides recommendations for how each of the factors should be determined*.” The results of the four-factor analysis would be incorporated into the long term strategy which must “*include the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress.*”[7]

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[5] The four factors are presented in 40 CFR 51.308(f)(2)(i): cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts of compliance and remaining useful life of the source.

[6] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[7] 40 CFR 51.308(f)(3)

The reasonable progress goals are determined based on several criteria, including an evaluation of the "*rate of progress needed to attain natural visibility conditions by the year 2064…. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction measures needed to achieve it for the period covered by the implementation plan.*"[8]

2 Current Visibility in BWCAW, Voyageurs, and Isle Royale

The data from the IMPROVE monitoring network for BWCAW, Voyageurs, and Isle Royale are available on MPCA's website[9]. As shown in figures 1 through 3, the visibility at each Class I area has been improving since 2009 and is already below the 2028 uniform rate of progress (URP)[10]. The observed visibility improvement could be attributed to emission reductions from regulated stationary sources due to a variety of reasons, including:

- installation of best available retrofit technology (BART) during the first RHR implementation period,
- emission reductions from a variety of industries, including the pulp and paper sources, due to updated rules and regulations, and
- transition of power generation systems from coal to natural gas and renewables (wind and solar).

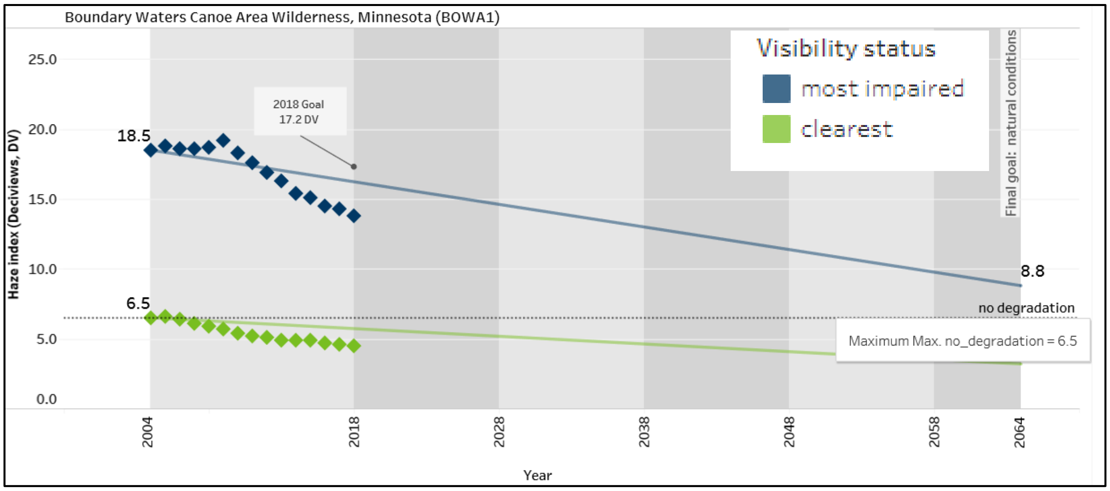

Figure 1: BWCAW Current Visibility Conditions

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[8] 40 CFR 51.308(d)(1)(i)(B)

[9] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

[10] The URP is determined based on the slope of the line from baseline conditions (2000-2004) to the natural visibility conditions in 2064

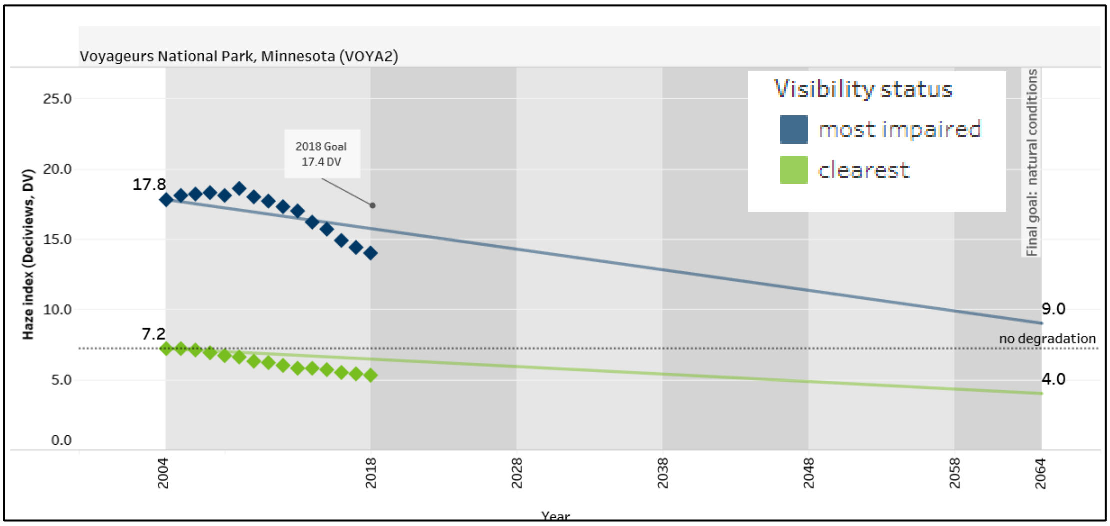

Figure 2: Voyageurs Current Visibility Conditions

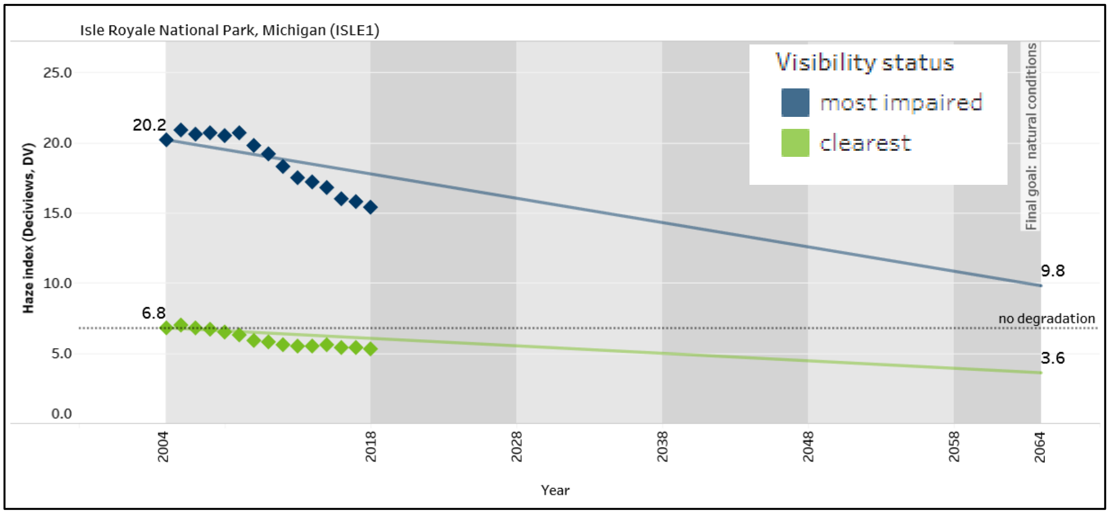

Figure 3: Isle Royale Current Visibility Conditions

Some of these emission reductions have recently occurred but are not fully reflected in the 5-year average monitoring data presented in figures 1 through 3. For example, Minnesota Power retired two coal-fired boilers at the Boswell Energy Center in Cohasset at the end of 2018. In addition, the compliance schedule is still in progress for the NO_X emission reductions required by the Taconite Federal Implementation Plan (FIP) Establishing BART for Taconite Plants (40 CFR 52.1235). Furthermore, there are others emission reduction projects that are scheduled to occur in Minnesota prior to 2028, the end of the second RHR implementation period (e.g., Xcel Energy boiler retirements as detailed in their Upper Midwest Integrated Resource Plan, 2020-2034). These emission reductions will further improve the visibility in the Class I areas.

3 EPA Guidance for State Implementation Plans

MPCA's January 29, 2020, RFI stated that the four-factor analysis should follow EPA's guidance[11] that provides recommendations for how each of the factors should be determined. Additionally, EPA also provides states guidance on selecting sources which must conduct a four-factor analysis.

The guidance says that the state will determine which emission control measures are necessary to make reasonable progress in the affected Class I areas[12]. However, as discussed in Section 2, the current sustained progress towards visibility goals in BWCAW, Voyageurs, and Isle Royale is such that the MPCA may tolerate the current reduction trajectory of emission reductions during the second implementation period. The MPCA would be warranted to further consider the flexibility allowed in the RHR to "*reasonably select a set of sources for an analysis of control measures.*"[13] The monitoring information will help MPCA "*explain why the decision is consistent with the requirement to make reasonable progress.*"[14]

4 EPA Guidance for Effectively Controlled Sources

EPA guidance states that it "may be reasonable for a state not to select an effectively controlled source"[15] for the four-factor analysis with the rationale that "*it is reasonable to assume for the purposes of efficiency and prioritization that a full four-factor analysis would likely result in the conclusion that no further controls necessary*."[16] EPA identified potential scenarios that "*EPA believes it may be reasonable for a state not to select a particular source for further analysis*." However, EPA clarified that the associated scenarios are not a comprehensive list but are merely to illustrate examples for the state to consider.

One of the "effectively controlled" scenarios is for sources that went through a best available control technology (BACT) review with a construction permit issued on or after July 31, 2013.[17] EPA notes that the BACT control equipment review methodologies are "*similar to, if not more stringent than, the four statutory factors for reasonable progress.*" As presented below, an extension of the BACT review scenario is for sources that have existing permit limits, independent of the statutory basis (e.g., air dispersion modeling, PSD avoidance limit, etc.), which are consistent or sufficiently similar to recent BACT determinations for similar sources. Because the limits are similar to BACT, this extension is consistent with EPA's conclusion that a four-factor analysis "*would likely result in the conclusion that no further controls are necessary.*"

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[11] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[12] Ibid, Page 9.

[13] Ibid.

[14] Ibid, Page 23.

[15] Ibid, Page 22.

[16] Ibid, Page 23.

[17] Ibid.

4.1 Recovery Furnace (EQUI 9 / EU 320)

The RFI requested a four-factor analysis for NO_X emissions from the Recovery Furnace which is a combustion unit that burns black liquor solids (BLS) from the Kraft pulping process to recover spent cooking chemicals. The combustion process generates heat which is recovered by steam generation. The combustion process results in NO_X and other emissions.

The Recovery Furnace has not undergone a NO_X BACT review since July 31, 2013, so this unit does not directly meet this scenario. However, the current NO_X limit[18] (100 lb/hr per 30-day rolling average, which is equivalent to 80 ppm at 8% oxygen (O_2)) was compared to recent determinations in EPA's RBLC database (Attachment A) and the limit is consistent with NO_X limits from recent BACT determinations (e.g., 85 ppm at 8% O_2[19], 120 ppm at 8% O_2[20]).

Because the current NO_X emission limit is similar to recent BACT determinations and BACT control equipment reviews are "*similar to if not more stringent than*" the four-factor analysis methodology, it is unlikely that additional controls would be available to further reduce emissions. Therefore, this unit is sufficiently similar BACT scenario and MPCA can justify that a four-factor analysis need not be completed.

4.2 Boiler #2 (EQUI 16 / EU 430)

The RFI requested a four-factor analysis for NO_X and SO_2 emissions Boiler #2 which is an industrial boiler that is permitted to burn the following fuels: [21]

- Biomass (commonly referred to as "hog fuel")
- WWTP Sludge
- Natural Gas
- Non-Condensable Gas (NCG)

The associated combustion results in NO_X and SO_2 emissions, among other emissions.

NO_X: Boiler #2's current NO_X limit[22] (100.2 lb/hr, which is equivalent to 0.25 lb/MMBtu at the maximum firing rate) was compared to recent determinations in EPA's RBLC database (Attachment B) and the limit is consistent with NO_X limits from recent BACT determinations (e.g., two determinations[23,24] with 0.3 lb/MMBtu limits).

Because the current NO_X emission limit is similar to recent BACT determinations and BACT control equipment reviews are "*similar to if not more stringent than*" the four-factor analysis methodology, it is unlikely that additional controls would be available to further reduce emissions. Therefore, this unit is

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[18] Title V Operating Permit (TVOP) Condition 5.13.7

[19] 2019 BACT determination for Sun Bio Materials Company (AR-0161)

[20] 2015 BACT determination for Rocktenn CP, LLC (AL-0302)

[21] Permit 07100002-014 Condition 5.17.14 limits fuel burned to "bark, wood refuse, wastewater treatment sludge, paper, and natural gas. Non-condensable gas (NCG) is also oxidized in Boiler #2."

[22] TVOP Condition 5.17.7

[23] 2010 BACT determination for Boise White Paper (AL-0250)

[24] 2014 BACT determination for Abengoa Bioenergy Biomass of Kansas (KS-0034)

sufficiently similar BACT scenario and MPCA can justify that a four-factor analysis need not be completed.

SO_2: When considering the SO2 emissions from Boiler #2, it is important to note:

- The primary fuel is hog fuel, a biomass which is primarily bark from the facility de-barking process. This fuel is inherently low in sulfur.
- Natural gas is a supplemental fuel and is also a low-sulfur fuel.
- Most of the SO_2 emissions from the boiler are a direct result of Non-Condensable Gas (NCG) combustion. However, Boiler #2 is the secondary NCG combustion source[25] and is only utilized when the primary NCG combustion source (Lime Kiln (EQUI 13 / EU 340)) is unavailable; Boiler #1 (EQUI 15 / EU 420) is the tertiary NCG combustion device[26].
- Boiler #2 has an SO_2 emission limit (9.4 lb/hr as a 12-hr rolling average, which is equivalent to 0.024 lb/MMBtu at the maximum firing rate) which applies when NCG is not being combusted.[27]
- Boiler #1 and Boiler #2 have a combined SO_2 emission limit (115 tons per rolling 12-month period) which applies when burning NCG in either of the backup combustion sources.[28]
- Maintaining the ability to combust the NCG in the backup combustion sources is part of the overall strategy for limiting emissions of hazardous air pollutants because 40 CFR Part 63 Subpart S (National Emission Standards for Hazardous Air Pollutants from the Pulp and Paper Industry) limits the amount of time that NCG can be vented to the atmosphere without combustion.
- Additionally, maintaining the ability to combust NCG in the backup combustion sources is an engineered control to maintain the continued safe operation of the Kraft pulping equipment and process.

Boiler #2's current SO_2 limit, which applies when NCG is not being combusted (9.4 lb/hr as a 12-hr rolling average, which is equivalent to 0.024 lb/MMBtu at the maximum firing rate)[29], was compared to recent determinations in EPA's RBLC database (Attachment C). The limit is consistent with SO_2 limits from recent BACT determinations for similar sources (e.g., 0.025 lb/MMBtu[30], 0.21 lb/MMBtu[31]).

The TVOP limits the SO_2 emissions from the backup NCG combustion sources (Boiler #1 and Boiler 2) to 115 tons per rolling 12-month period.[32] As stated above, maintaining the ability to combust the NCG in the backup combustion sources is part of the overall strategy for limiting emissions of hazardous air pollutants as required by 40 CFR Part 63 Subpart S. Boise works diligently to maintain the availability of the primary NCG combustion source (Lime Kiln) which limits the actual emissions from the facility. For

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[25] TVOP Condition 5.3.3

[26] Ibid.

[27] TVOP Condition 5.17.6

[28] TVOP Condition 5.3.6

[29] TVOP Condition 5.17.6

[30] 2019 BACT determination for Sun Bio Materials Company (AR-0161)

[31] 2014 BACT determination for Abengoa Bioenergy Biomass of Kansas (KS-0034)

[32] TVOP Condition 5.3.6

example, the maximum annual SO_2 emissions from Boiler #2 in the past five years was 35.4 tons which resulted from 436 hours (18.2 days) of NCG combustion. Although the actual emissions provide for a large margin of compliance, Boise could not take a more stringent limit because the existing limit could be necessary if an unanticipated downtime or failure of the primary combustion source were to occur.

In regards to the installation of SO_2 controls on Boiler #2 for the NCG combustion scenario, it is unlikely that any controls would be cost effective. This conclusion is based on designing the SO_2 controls to treat the full volume of Boiler #2 flue gas (i.e., a large annualized capital expenditure) but only operating the equipment when NCG is being combusted (e.g., the maximum SO_2 emissions from Boiler #2 in the past five years resulted from 18.2 days of NCG combustion). The annualized cost will be high but the low utilization of the control equipment will not result in large actual emission reductions and the cost would therefore not be cost-effective.

The SO_2 emission limit when NCG is not being combusted is similar to recent BACT determinations and BACT control equipment reviews are "*similar to if not more stringent than*" the four-factor analysis methodology, it is unlikely that additional controls would be available to further reduce emissions. In addition, the SO_2 emission limit when NCG is being burned is necessary for the backup combustion sources to ensure control of HAP emissions but the installation of control equipment to operate only when combustion NCG would not be cost effective. Therefore, the MPCA can justify that a four-factor analysis need not be completed.

5 Conclusion

As described in Section 2, the current visibility in the nearby Class I areas is already below the 2028 glidepath, so MPCA does not need to consider an excessive reasonable progress goal for the SIP revision that is due in 2021. Furthermore, as described in Section 4, there is sufficient justification to consider the Recovery Furnace and Boiler #2 as “effectively controlled” sources. Thus, it “*may be reasonable for a state not to select an effectively controlled source*” to conduct a four-factor analysis because “*there will be only a low likelihood of a significant technological advancement that could provide further reasonable emission reductions*.”[33] Therefore, Boise requests that your RFI dated January 29, 2020, be withdrawn for the Recovery Furnace and Boiler #2. We will continue to proceed with a four factor analysis for Boiler #1 as directed in the RFI dated January 29, 2020.

We are available at your convenience to discuss this request in detail. Please advise if a telephone conference is desired. You may contact Kara Huziak at karahuziak@boisepaper.com with questions or to request a meeting.

Thank you for considering our request.

Sincerely,

Mike Wagner
Mill Manager

Attachments:

A. RBLC Summary: NO_X from Recovery Furnaces
B. RLBC Summary: NO_X from Hog Fuel Boilers
C. RBLC Summary: SO_2 from Hog Fuel Boilers

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[33] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, Page 23.

Boise White Paper LLC
Regional Haze "Effectively Controlled" Source Scenario Comparison Analysis
Attachment A: Recovery Furnace NOx RBLC Search

Pollutant Name: NOx

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
AL-0266	GEORGIA PACIFIC BREWTON LLC	GEORGIA PACIFIC LLC	AL	502-0001-X044	322130	06/11/2014 ACT	Kraft Pulp & Paper mdu	No.4 Recovery & Smelt Tank	Black Liquor	1355	MMBTU/ hr	Nitrogen Oxides (NOx)	Staged air combustion	90	PPM@8%O2	3HRS AVG	BACT-PSD	221	LB/H	3HRS AVG	0		
AL-0266	GEORGIA PACIFIC BREWTON LLC	GEORGIA PACIFIC LLC	AL	502-0001-X044	322130	06/11/2014 ACT	Kraft Pulp & Paper mdu	No. 4 REC & Smelt	Natural Gas	1355	mmbtu	Nitrogen Oxides (NOx)	Gas Combustion	0.2	LB/MMBTU	3 HRS AVG	BACT-PSD	145.12	LB/H	3 HRS AVG	0		
AL-0274	BOISE WHITE PAPER, LLC	BOISE WHITE PAPER, LLC	AL	102-0001-X011	322121	02/04/2015 ACT	Paper mill	Recovery Furnace - Non-Direct Contact with Dry -	Black Liquor Solids (BLS)	2.88	million lbs. of BLS	Nitrogen Oxides (NOx)		90	PPMDV	@8% O2	BACT-PSD	105.8	LB/H	3-HR. ROLLING	0		
AL-0302	ROCKTENN STEVENSON	ROCKTENN CP, LLC	AL	705-0014-X014	322130	04/29/2015 ACT	Pulp & Paper Mill	Recovery Boiler	Black Liquid	58334	LB/LB BL	Nitrogen Oxides (NOx)		120	PPM@8%O2	30 DAYS AVG	BACT-PSD	72.92	LB/H	3 HRS AVG	0		
AL-0320	GP BREWTON	GEORGIA-PACIFIC BREWTON LLC	AL	502-0001-X044	322130	01/03/2018 ACT		No. 4 Recovery Furnace	Black Liqour	1355	MMBtu/hr	Nitrogen Oxides (NOx)		90	PPMV @8% O2		BACT-PSD	221.9	LB/HR	3 HR	0		
AR-0156	GREEN BAY PACKAGING - ARKANSAS KRAFT DIVISION	GREEN BAY PACKAGING - ARKANSAS KRAFT DIVISION	AR	0224-AOP-R21	322130	02/08/2019 ACT	paperboard mill	Recovery Boiler	black liquor solids	401400	T/YR	Nitrogen Oxides (NOx)		80	LB/H		OTHER CASE-BY-CASE	313.1	T/YR		0		
*AR-0161	SUN BIO MATERIAL COMPANY	SUN BIO MATERIAL COMPANY	AR	2384-AOP-R0	322110	09/23/2019 ACT	A kraft paper mill designed with one high yield Kraft softwood Fiberline and two linerboard machiens. The plant is initially sized to support an approximate, nominal linerboard production capacity of 4,400 machine dry tons per day at varying base weights.	Recovery Boiler	Black Liquor Solids	2900	MMBtu/hr	Nitrogen Oxides (NOx)	Quaternary Air/Staged Combustion	85	PPMVD @ 8% O2	3 1-HOUR TESTS	BACT-PSD	0			0		
*AR-0161	SUN BIO MATERIAL COMPANY	SUN BIO MATERIAL COMPANY	AR	2384-AOP-R0	322110	09/23/2019 ACT	A kraft paper mill designed with one high yield Kraft softwood Fiberline and two linerboard machiens. The plant is initially sized to support an approximate, nominal linerboard production capacity of 4,400 machine dry tons per day at varying base weights.	Lime Kiln	Natural Gas	225	MMBtu/hr	Nitrogen Oxides (NOx)	Good Combustion Practices	180	PPMVD @ 10% O2	3 1-HOUR TESTS	BACT-PSD	0			0		
*AR-0161	SUN BIO MATERIAL COMPANY	SUN BIO MATERIAL COMPANY	AR	2384-AOP-R0	322110	09/23/2019 ACT	A kraft paper mill designed with one high yield Kraft softwood Fiberline and two linerboard machiens. The plant is initially sized to support an approximate, nominal linerboard production capacity of 4,400 machine dry tons per day at varying base weights.	Power Boiler	Biomass	1200	MMBtu/hr	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	0.06	LB/MMBTU	3-HOUR	BACT-PSD	0			0		

Boise White Paper LLC
Regional Haze "Effectively Controlled" Source Scenario Comparison Analysis
Attachment B: Hog Fuel Boiler NOx RBLC Search

Pollutant Name: NOx

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
AL-0250	BOISE WHITE PAPER	BOISE WHITE PAPER, LLC	AL	102-0001	322121	03/23/2010 ACT		COMBINATION BOILER	WOOD	435	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNERS	0.3	LB/MMBTU	3 H	BACT-PSD	130.5	LB/H	3 H	0		
*AR-0161	SUN BIO MATERIAL COMPANY	SUN BIO MATERIAL COMPANY	AR	2384-AOP-R0	322110	09/23/2019 ACT	A kraft paper mill designed with one high yield Kraft softwood Fiberline and two linerboard machiens. The plant is initially sized to support an approximate, nominal linerboard production capacity of 4,400 machine dry tons per day at varying base weights.	Power Boiler	Biomass	1200	MMBtu/hr	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	0.06	LB/MMBTU	3-HOUR	BACT-PSD	0			0		
CA-1203	SIERRA PACIFIC INDUSTRIES-LOYALTON	SIERRA PACIFIC INDUSTRIES	CA	SAC 87-01-A	221119	08/30/2010 ACT	20 MW COGENERATION POWER PLANT	RILEY SPREADER STOKER BOILER - Transient Period (see notes)	WOOD	335.7	MMBTU/H	Nitrogen Oxides (NOx)	SELECTIVE NON-CATALYTIC REDUCTION (SNCR)	102	PPM	@12% CO2, 8-HR ROLLING AVG	BACT-PSD	65	LB/H	8-HR ROLLING AVG	0		
CA-1203	SIERRA PACIFIC INDUSTRIES-LOYALTON	SIERRA PACIFIC INDUSTRIES	CA	SAC 87-01-A	221119	08/30/2010 ACT	20 MW COGENERATION POWER PLANT	RILEY SPREADER STOKER BOILER	WOOD	335.7	MMBTU/H	Nitrogen Oxides (NOx)	SELECTIVE NON-CATALYTIC REDUCTION (SNCR)	80	PPM	@12% CO2, 8-HR ROLLING AVG	BACT-PSD	50.75	LB/H	8-HR ROLLING AVG	0		
CA-1225	SIERRA PACIFIC INDUSTRIES-ANDERSON DIVISION	SIERRA PACIFIC INDUSTRIES	CA	SAC 12-01	321113	04/25/2014 ACT	31 MW COGENERATION AND LUMBER MANUFACTURING FACILITY	STOKER BOILER (NORMAL OPERATION)	BIOMASS	468	MMBTU/H	Nitrogen Oxides (NOx)	SNCR	0.13	LB/MMBTU	12-MONTH ROLLING BASIS	BACT-PSD	0.15	LB/MMBTU	3-HOUR BLOCK AVERAGE	0		
CA-1225	SIERRA PACIFIC INDUSTRIES-ANDERSON DIVISION	SIERRA PACIFIC INDUSTRIES	CA	SAC 12-01	321113	04/25/2014 ACT	31 MW COGENERATION AND LUMBER MANUFACTURING FACILITY	STOKER BOILER (STARTUP & SHUTDOWN PERIODS)	BIOMASS	468	MMBTU/H	Nitrogen Oxides (NOx)	SNCR	70.2	LB/H	8-HR AVG (STARTUP PERIODS)	BACT-PSD	70.2	LB/H	8-HR AVG (SHUTDOWN PERIODS)	0		
CT-0156	MONTVILLE POWER LLC	NRG ENERGY	CT	107-0056	221119	04/06/2010 ACT	43 MW STOKER FIRED BIOMASS; 82 MW TANGENTIALLY FIRED NATURAL GAS/ULS DISTILLATE UTILITY BOILER (7% ANNUAL CAPACITY FACTOR)	42 MW Biomass utility boiler	Clean wood	600	MMBTU/H	Nitrogen Oxides (NOx)	Regenerative SCR	0.06	LB/MMBTU	24 HR BLOCK	LAER	0			0		
CT-0162	PLAINFIELD RENEWABLE ENERGY, LLC	PLAINFIELD RENEWABLE ENERGY, LLC	CT	145-0049	221119	12/29/2010 ACT	37.5 MW Biomass Power Plant	Fluidized Bed Gasification	Wood	523.1	MMBtu/hr	Nitrogen Oxides (NOx)	SNCR	0.075	LB/MMBTU		LAER	45.3	PPMVD @7% O2	24 HR BLOCK	0		
GA-0141	WARREN COUNTY BIOMASS ENERGY FACILITY	OGETHORPE POWER CORPERATION	GA	4911-301-0016-P-01-0	221119	12/17/2010 ACT	The proposed project will include: a bubbling fluidized bed boiler with a maximum total heat input capacity of 1,399 MMBTU/H, 2 fire water pump emergency engines; a raw material handling & storage area; a sorbent storage silo; a boiler bed sand silo, a sand day	Boiler, Biomass Wood	Biomass wood	100	MW	Nitrogen Oxides (NOx)	Selective non-catalytic reduction system (SNCR)	0.1	LB/MMBTU	30 D ROLLING AV / CONDITION 2.9	BACT-PSD	648	TONS	12 MONTH ROLLING TOTAL / CONDITION 2.18	0		
*KS-0034	ABENGOA BIOENERGY BIOMASS OF KANSAS (ABBK)	ABENGOA BIOENERGY BIOMASS OF KANSAS (ABBK)	KS	C-11396	325193	05/27/2014 ACT	Abengoa Bioenergy Biomass of Kansas (ABBK) intends to install and operate a biomass-to-ethanol and biomass-to-energy production facility near Hugoton, Kansas.	biomass to energy cogeneration bioler	different types of biomass	500	MMBtu/hr	Nitrogen Oxides (NOx)	Selective Catalytic Reduction System (SCR) and an over-fire system (OFA)	0.3	LB/MMBTU	30-DAY ROLLING, INCLUDES SSM	BACT-PSD	157.5	LB/HR	1-HR AVE, INCLUDES SSM	0		
ME-0037	VERSO BUCKSPORT LLC	VERSO BUCKSPORT LLC	ME	A-22-77-4-A	322121	11/29/2010 ACT	Existing pulp (groundwood and thermomechanical) and paper making facility.	Biomass Boiler 8	Biomass	814	MMBTU/H	Nitrogen Oxides (NOx)	SNCR	0.15	LB/MMBTU	30 DAY ROLLING	BACT-PSD	244.2	LB/H		0		

Boise White Paper LLC
Regional Haze "Effectively Controlled" Source Scenario Comparison Analysis
Attachment C: Hog Fuel Boiler SO2 RBLC Search

Pollutant Name: SO2

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
*AR-0161	SUN BIO MATERIAL COMPANY	SUN BIO MATERIAL COMPANY	AR	2384-AOP-R0	322110	09/23/2019 ACT	A kraft paper mill designed with one high yield Kraft softwood Fiberline and two linerboard machiens. The plant is initially sized to support an approximate, nominal linerboard production capacity of 4,400 machine dry tons per day at varying base weights.	Power Boiler	Biomass	1200	MMBtu/hr	Sulfur Dioxide (SO2)	FGD/Dry Sorbent Injection	0.025	LB/MMBTU	3 1-HOUR TESTS	BACT-PSD	0			0		
CT-0156	MONTVILLE POWER LLC	NRG ENERGY	CT	107-0056	221119	04/06/2010 ACT	43 MW STOKER FIRED BIOMASS; 82 MW TANGENTIALLY FIRED NATURAL GAS/ULS DISTILLATE UTILITY BOILER (7% ANNUAL CAPACITY FACTOR)	42 MW Biomass utility boiler	Clean wood	600	MMBTU/H	Sulfur Oxides (SOx)	Low sulfur fuels	0.025	LB/MMBTU	3 HR BLOCK	BACT-PSD	0			0		
CT-0162	PLAINFIELD RENEWABLE ENERGY, LLC	PLAINFIELD RENEWABLE ENERGY, LLC	CT	145-0049	221119	12/29/2010 ACT	37.5 MW Biomass Power Plant	Fluidized Bed Gasification	Wood	523.1	MMBtu/hr	Sulfur Dioxide (SO2)	Spray Dryer, Bed Injection	0.035	LB/MMBTU		OTHER CASE-BY-CASE	15.4	PPMVD @7% O2	3 HR BLOCK	0		
GA-0141	WARREN COUNTY BIOMASS ENERGY FACILITY	OGETHORPE POWER CORPERATION	GA	4911-301-0016-P-01-0	221119	12/17/2010 ACT	The proposed project will include: a bubbling fluidized bed boiler with a maximum total heat input capacity of 1,399 MMBTU/H, 2 fire water pump emergency engines; a raw material handling & storage area; a sorbent storage silo; a boiler bed sand silo, a sand day	Boiler, Biomass Wood	Biomass wood	100	MW	Sulfur Oxides (SOx)	Dust sorbent injection system	0.01	LB/MMBTU	30 D ROLLING AV / CONDITION 2.12	BACT-PSD	56	TONS	12 MONTH ROLLING TOTAL / CONDITION 2.20	0		
*KS-0034	ABENGOA BIOENERGY BIOMASS OF KANSAS (ABBK)	ABENGOA BIOENERGY BIOMASS OF KANSAS (ABBK)	KS	C-11396	325193	05/27/2014 ACT	Abengoa Bioenergy Biomass of Kansas (ABBK) intends to install and operate a biomass-to-ethanol and biomass-to-energy production facility near Hugoton, Kansas.	biomass to energy cogeneration bioler	different types of biomass	500	MMBtu/hr	Sulfur Dioxide (SO2)	Injection of sorbent (lime) in combination with a dry flue gas desulfurization (FGD) system	0.21	LB/MMBTU	30-DAY ROLLING, INCLUDES SSM	BACT-PSD	110.25	LB/HR	MAX 1-HR, INCLUDES SS, EXCLUDES MALFUNCT	0		
LA-0249	RED RIVER MILL	INTERNATIONAL PAPER CO	LA	PSD-LA-562(M-4)	322130	05/09/2011 ACT	KRAFT PULP MILL WHICH PRODUCES UNBLEACHED LINERBOARD	NO. 2 HOGGED FUEL BOILER	HOGGED FUEL/BARK	992.43	MMBTU/H	Sulfur Dioxide (SO2)	USE OF LOW SULFUR FUELS	60	LB/H	HOURLY MAXIMUM	BACT-PSD	262.8	T/YR	ANNUAL MAXIMUM	0.06	LB/MMBTU	
ME-0037	VERSO BUCKSPORT LLC	VERSO BUCKSPORT LLC	ME	A-22-77-4-A	322121	11/29/2010 ACT	Existing pulp (groundwood and thermomechanical) and paper making facility.	Biomass Boiler 8	Biomass	814	MMBTU/H	Sulfur Dioxide (SO2)	0.7% sulfur when firing oil	0.8	LB/MMBTU	3-HR AVERAGE	BACT-PSD	651.2	LB/H		0		

Appendix A.2

Regional Haze Correspondence with Hassan Bouchareb

Dated May 29, 2020

-------- Original message --------
From: "Bouchareb, Hassan (MPCA)" <hassan.bouchareb@state.mn.us>
Date: 5/29/20 12:12 PM (GMT-06:00)
To: "Huziak, Kara" <KaraHuziak@BoisePaper.com>
Cc: "Rein, Patrick" <PatrickRein@boisepaper.com>
Subject: [EXTERNAL] RE: Regional Haze Request - NOx question

Ms. Huziak,

Thank you for providing this information. Based on this information and information included in your request, I agree that the recovery furnace and boiler #2 qualify as effectively controlled and Boise White Paper does not need to conduct a four factor analysis for those emission units as requested in the January 29, 2020 RFI letter. Please note that I may have additional questions for you regarding these units as I work on preparing Minnesota's regional haze SIP; potentially in describing the units and expected operations for various portions of the regional haze rules.

I have one request for you that would be helpful for me. Eventually, I will be working to post the collection of four-factor analyses and facility responses to the MPCA's external website to facilitate review by interested, external folks. Would you please include your request to withdraw the four factor analysis for the recovery furnace and boiler #2 with your response to the RFI letter for Boiler #1?

It would be helpful to have everything in one package so I can provide it to our publication/web support teams when we get to that point.

Please let me know if you have any questions.

Thank you!

Hassan M. Bouchareb | Engineer
Minnesota Pollution Control Agency (MPCA)
Office: (651) 757-2653 | Fax: (651) 296-8324
Pronouns: he/him/his
Hassan.Bouchareb@state.mn.us | www.pca.state.mn.us

From: Huziak, Kara <KaraHuziak@BoisePaper.com>
Sent: Thursday, May 21, 2020 3:45 PM
To: Bouchareb, Hassan (MPCA) <hassan.bouchareb@state.mn.us>
Subject: Regional Haze Request - NOx question

Mr. Bouchareb,

Thank you for the update. Regarding the history of the BACT analysis for the Recovery Furnace, we've prepared the following table which provides the history of the permitting for the Recovery Furnace with a focus on the NO_X emissions limit changes. It is important to note that the existing permit limit (*110* *lbs/hour using 30-day Rolling Average; This is equivalent to 80 ppm on a dry basis, corrected to 8% oxygen*) is the result of a BACT analysis. It is also important to note that the Recovery Furnace utilizes a two-stage tertiary air system (i.e., quaternary overfire air) which is the control system listed as BACT in the RBLC and in Sappi's 2017 major air permit amendment (Air Permit Number 01700002-101 – see the BACT analysis in Section 3.3.3 of the TSD).

Permit #	Issued Date	Description
001	09/1990	The NO_X permit limit in the first Title V permit was: - Nitrogen Oxides: less than or equal to 86.9 lbs/hour using 30-day Rolling Average. This is equivalent to 80 ppm on a dry basis, corrected to 8% oxygen. - Title I Condition: 40 CFR Section 52.21 (modeling and netting); Minn. R. 7007.3000
003	10/2000	This permit was for the Efficiency Improvement Project which was permitted under PSD. The TSD describes the NO_X limit as follows: - NO_X limit increased from 86.9 to 94.5 lbs/hour and identified as BACT limit; the previous limit was not a BACT limit. Although the NO_X limit on this emission unit has been increased, the NO_X emission cap for the facility has not been increased. The NO_X emission rate on a pound per ton of black liquor solids basis is the same as what it was previously, but since the black liquor production will be increasing, the lbs/hour emission rate will increase. The permit limit was listed as follows: - Nitrogen Oxides: less than or equal to 94.5 lbs/hour using 30-day Rolling Average. - Title I Condition: 40 CFR Section 52.21(j) (BACT limit); Minn. R. 7007.3000
006	11/2004	This permit amendment included an increase in the NO_X emission limit for the Recovery Furnace. The NO_X emission limit increase was based on an update to the NO_X BACT analysis because the existing permit limit was a BACT limit. The permit limit was listed as follows: - Nitrogen Oxides: less than or equal to 102 lbs/hour using 30-day Rolling Average. This is equivalent to 80 ppm on a dry basis, corrected to 8% oxygen. - Title I Condition: 40 CFR Section 52.21(j) (BACT limit); Minn. R. 7007.3000
009	10/2008	This permit amendment included increase to the Total Facility black liquor solids (BLS) production limit from 41,000 to 44,200 tons/month and the NO_X emission limit. The permit amendment also increased the NO_X emission limit which included an update to the NO_X BACT analysis because the existing permit limit was a BACT limit. As described in the TSD, "*the requested NOx and CO emission limits increase is necessary to maintain the mass emission limits (lb/hr) in proper proportion to the maximum permitted annual BLS rate*" (Air Permit 07100002-009 – see page 16 of the TSD). The permit limit was listed as follows: - Nitrogen Oxides: less than or equal to 110 lbs/hour using 30-day Rolling Average. This is equivalent to 80 ppm on a dry basis, corrected to 8% oxygen. - Title I Condition: 40 CFR Section 52.21(j) (BACT limit); Minn. R. 7007.3000
010	03/2009	This Major Amendment was requested by the facility to allow for the blending of distillate oil (#1 and #2) with the black liquor solids (BLS) to provide the facility with additional fuel flexibility for the Recovery Furnace (Emission Unit 320). However, there was no change to the NO_X emission limit.

014	06/2017	This permit action is the reissuance of the Part 70 operating permit. In addition to the reissuance, a major permit amendment was incorporated into the permit to increase the total facility BLS production limit from 44,200 to 46,410 tons per month using a 12-month rolling average. However, the facility did not request a change to the NO$_X$ emission limit.
101	04/2020	This permit action is a Major Amendment for an increase in BLS throughput to 49,890 tons/month. However, the facility did not request a change to the NO$_X$ emission limit.

Please let me know if you have questions or need additional assistance for your review.

Thank you,

Kara Huziak

Environmental, Air
400 2nd Street
International Falls, MN 56649

218.285.5449 Office
218.417.0624 Cell

From: Bouchareb, Hassan (MPCA) <hassan.bouchareb@state.mn.us>
Sent: Wednesday, May 20, 2020 2:12 PM
To: Huziak, Kara <KaraHuziak@BoisePaper.com>
Cc: Rein, Patrick <PatrickRein@boisepaper.com>
Subject: [EXTERNAL] RE: Regional Haze Request

Hello Kara,

Thanks for your patience so far! I'm currently reviewing your request and so far it looks like we'll likely be able to grant the request. One thing you could help me with is the history of the BACT analysis for the Recovery Furnace (i.e., when it was first completed, updates since then, etc.). I was looking through the previous permits for Boise and I noticed the lb/hr NO$_X$ values have changed while the equivalent ppm concentration has remained the same. From my review so far, it looks like that is due to production/capacity increases that allowed the furnace to process more BLS but it would be helpful if you could provide the history of the changes to help clarify how the ppm value from the previous BACT analysis has remained while the hourly emission rates have increased.

Additionally, It's not clear to me if controls are implemented to allow Boise to meet these NO$_X$ limits or if it is managed through other methods. I see that CEMS are used to demonstrate compliance with the limits, but if you could help clarify what, if any, controls are implemented for NO$_X$ that would be helpful as well.

Let me know if you have any questions.

Thanks again!

Hassan M. Bouchareb | Engineer
Minnesota Pollution Control Agency (MPCA)
Office: (651) 757-2653 | Fax: (651) 296-8324
Pronouns: he/him/his
Hassan.Bouchareb@state.mn.us | www.pca.state.mn.us

From: Huziak, Kara <KaraHuziak@BoisePaper.com>
Sent: Wednesday, May 20, 2020 9:09 AM
To: Bouchareb, Hassan (MPCA) <hassan.bouchareb@state.mn.us>
Cc: Rein, Patrick <PatrickRein@boisepaper.com>
Subject: RE: Regional Haze Request

Hello Mr. Bouchareb,

I am writing to follow up on our recent 4-Factor analysis request. Do you have any questions or require clarification regarding the request? We are happy to meet with you by phone to discuss further.

Thank you,

Kara Huziak

Environmental, Air
400 2nd Street
International Falls, MN 56649

218.285.5449 Office
218.417.0624 Cell

From: Huziak, Kara
Sent: Tuesday, May 12, 2020 12:36 PM
To: Hassan.Bouchareb@State.mn.us
Cc: Rein, Patrick <PatrickRein@boisepaper.com>
Subject: Regional Haze Request

Mr. Bouchareb,

Please find attached a digital copy of a letter mailed to your attention requesting further consideration for EQUI 09 and EQUI 16 at the International Falls, MN (Air Permit 07100002-101, agency interest #443).

We look forward to discussing this request with you.

Thank you,

Kara Huziak

Environmental, Air
400 2nd Street
International Falls, MN 56649

218.285.5449 Office
218.417.0624 Cell

Appendix B

RACT/BACT/LAER Clearinghouse (RBLC) Review

Summary for Natural Gas Boilers for NO_X

Boise White Paper LLC
Appendix B: Natural Gas Boiler NOx RBLC Search

Pollutant Name: NOx
NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
VA-0328	C4GT, LLC	NOVI ENERGY	VA	52588	221112	04/26/2018 ACT	Natural gas-fired combined cycle power plant	Auxiliary Boiler	Natural Gas	902	mmcf/y	Nitrogen Oxides (NOx)	Low NOx burners	0.011	LB/MMBTU	CORRECTED TO 3% O2	BACT-PSD	1.2	LB/H		0		
TN-0162	JOHNSONVILLE COGENERATION	TENNESSEE VALLEY AUTHORITY	TN	970816F	221112	04/19/2016 ACT	Existing gas-fired combustion turbine with new heat recovery steam generator (HRSG) with duct burner and two new gas-fired auxiliary boilers.	Two Natural Gas-Fired Auxiliary Boilers	Natural Gas	450	MMBtu/hr	Nitrogen Oxides (NOx)	Good combustion design and practices, selective catalytic reduction (SCR), low-NOX burners with flue gas recirculation	0.013	LB/MMBTU		BACT-PSD	0			0		
TX-0576	PIPE MANUFACTURING STEEL MINI MILL	TPCO AMERICA INC	TX	PSDTX1188 AND 86860	331513	04/19/2010 ACT	converts scrap steel into seamless pipe	vacuum degasser boiler	natural gas	40	MMBTU/H	Nitrogen Oxides (NOx)	good combustion practice	0.1	LB/MMBTU		BACT-PSD	0			0		
PA-0306	TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	65-00990 C/E	221112	02/12/2016 ACT	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Nitrogen Oxides (NOx)	Good combustion practices and ULNOx burners	0.011	LB/MMBTU		LAER	9	PPMDV @ 15% O2		0		
LA-0314	INDORAMA LAKE CHARLES FACILITY	INDORAMA VENTURES OLEFINS, LLC	LA	PSD-LA-813	325199	08/03/2016 ACT	modify and restart-up a mothballed facility to produce 1,009 million lbs/yr of ethylene	boiler A and B (010 and 011)	natural gas/fuel gas	248	mm btu/hr (each)	Nitrogen Oxides (NOx)	good combustion practices; fueled by natural gas or process fuel gas; ULNB (FGR and economizer)	0.06	LB/MM BTU	THREE ONE-HOUR TEST AVERAGE	BACT-PSD	0			0		
LA-0314	INDORAMA LAKE CHARLES FACILITY	INDORAMA VENTURES OLEFINS, LLC	LA	PSD-LA-813	325199	08/03/2016 ACT	modify and restart-up a mothballed facility to produce 1,009 million lbs/yr of ethylene	boiler B-201	natural gas/fuel gas	229	mm btu	Nitrogen Oxides (NOx)	good combustion practices; fueled by natural gas or process fuel gas; ULNB (FGR and economizer)	0.06	LB/MM BTU	THREE ONE-HOUR TEST AVERAGE	BACT-PSD	0			0		
*TN-0164	TVA - JOHNSONVILLE COGENERATION	TENNESSEE VALLEY AUTHORITY	TN	972969	221112	02/01/2018 ACT	Combustion turbines and combined cycle plant	Two Auxiliary Boilers	Natural Gas	450	MMBtu/hr, each boiler	Nitrogen Oxides (NOx)	SCR, low-NOX burners, flue gas recirculation, good combustion design & practices	0.013	LB/MMBTU	30-DAY AVG EXCLUDING STARTUP & SHUTDOWN	BACT-PSD	0.2	LB/MMBTU	30-DAY AVG, APPLIES AT ALL TIMES	0		
OH-0354	KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	P0108853	325212	01/15/2013 ACT	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Nitrogen Oxides (NOx)	Low-NOx burners	0.12	LB/MMBTU	BURNING DISTILLATE OIL	N/A	392.83	T/YR		0.1	LB/MMBTU	BURNING NATURAL GAS
AK-0083	KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	AQ0083CPT06	325311	01/06/2015 ACT	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Nitrogen Oxides (NOx)	Ultra Low NOx Burners	0.01	LB/MMBTU	30-DAY AVERAGE	BACT-PSD	0			0		
AR-0121	EL DORADO CHEMICAL COMPANY	LSB INDUSTRIES, INC.	AR	0573-AOP-R16	325311	11/18/2013 ACT	CHEMICAL MANUFACTURING, INCLUDING NITRIC ACID PRODUCTION, SUFLURIC ACID PRODUCTION, AMMONIA PRODUCTION, AND AMMONIA NITRATE PRODUCTION	START-UP BOILER	NATURAL GAS	240	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNERS AND FLUE GAS RECIRCULATION	4.32	LB/H	ROLLING 3 HOUR AVERAGE	BACT-PSD	0.018	LB/MMBTU	ROLLING 3 HOUR AVERAGE	0		
IN-0263	MIDWEST FERTILIZER COMPANY LLC	MIDWEST FERTILIZER COMPANY LLC	IN	129-36943-00059	325311	03/23/2017 ACT	STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	NATURAL GAS AUXILIARY BOILERS (EU-012A, EU-012B,	NATURAL GAS	218.6	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNERS WITH FLUE GAS RECIRCULATION AND GOOD COMBUSTION PRACTICES	20.4	LB/MMCF EACH	3 HOUR AVERAGE	BACT-PSD	1877.39	MMCF/12 MONTH EACH	ROLLING AVERAGE	0		
IN-0179	OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	147-32322-00062	325311	09/25/2013 ACT	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MMBTU/HR, EACH	Nitrogen Oxides (NOx)	ULTRA LOW NOX BURNERS FLUE GAS RECIRCULATION	20.4	LB/MMCF	24-HR AVERAGE	BACT-PSD	0			0		
LA-0272	AMMONIA PRODUCTION FACILITY	DYNO NOBEL LOUISIANA AMMONIA, LLC	LA	(225) 219-3417"	2873	10/08/2012 ACT	2780 TON PER DAY AMMONIA PRODUCTION FACILITY	COMMISSIONING BOILERS 1 & 2 (CB-1 & CB-2)	NATURAL GAS	217.5	MM BTU/HR	Nitrogen Oxides (NOx)	FLUE GAS RECIRCULATION, LOW NOX BURNERS, AND GOOD COMBUSTION PRACTICES (I.E., PROPER DESIGN OF BURNER AND FIREBOX COMPONENTS; MAINTAINING	11.92	LB/H	HOURLY MAXIMUM	BACT-PSD	21.86	T/YR	ANNUAL MAXIMUM	0.05	LB/MM BTU	ANNUAL AVERAGE
TX-0811	LINEAR ALPHA OLEFINS PLANT	INEOS OLIGOMERS USA LLC	TX	136130 AND N250	325110	11/03/2016 ACT	Manufactures linear alpha olefins (LAO) from ethylene	Industrial-Sized Furnaces, Natural Gas-fired	natural gas	217	MM BTU / H	Nitrogen Oxides (NOx)	Low-NOX burners and Selective Catalytic Reduction (SCR). Ammonia slip limited to 10 ppmv (corrected to 3% O2) on a 1-hr block average.	0.006	LB / MM BTU	HHV BASIS, ANNUAL AVERAGE	LAER	0.014	LB/MMBTU	HHV BASIS, 1-HR AVERAGE	0		
OH-0374	GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	P0122594	221112	10/23/2017 ACT	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	Nitrogen Oxides (NOx)	low-NOx burners and flue gas recirculation	3.7	LB/H		BACT-PSD	9.25	T/YR	PER ROLLING 12 MONTH PERIOD	0.02	LB/MMBTU	
VA-0325	GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	52525	221112	06/17/2016 ACT	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	Nitrogen Oxides (NOx)	ultra low-NO$_x$ burners	0.011	LB/MMBTU		N/A	0			0		
MI-0427	FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	66-17	221112	11/17/2017 ACT	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	Nitrogen Oxides (NOx)	LNB that incorporate internal (within the burner) FGR and good combustion practices.	0.04	LB/MMBTU	30 DAY ROLLING AVERAGE	BACT-PSD	0			0		
MI-0423	INDECK NILES, LLC	INDECK NILES, LLC	MI	75-16	221112	01/04/2017 ACT	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	Nitrogen Oxides (NOx)	Low NOx burners/Flue gas recirculation and good combustion practices.	0.04	LB/MMBTU	30 DAY ROLLING AVG TIME PERIOD	BACT-PSD	0			0		
TX-0641	PINECREST ENERGY CENTER	PINECREST ENERGY CENTER LLC	TX	PSDTX1298	221122	11/12/2013 ACT	Combinec Cycle Electric Generating Plant	Auxiliary boiler	natural gas	150	MMBTU/H	Nitrogen Oxides (NOx)	low NOx burners	16	PPMVD	INITIAL STACK TEST, 3% OXYGEN	BACT-PSD	0			0		
TX-0708	LA PALOMA ENERGY CENTER	LA PALOMA ENERGY CENTER, LLC	TX	101542 PSDTX1288	221112	02/07/2013 ACT	The proposed project is a new electric power plant, fueled by pipeline quality natural gas. The design of the plant is standard combined cycle (CC) technology.	boiler	natural gas	150	MMBTU/H	Nitrogen Oxides (NOx)	low-NOx burners, limited use	0.02	LB/MMBTU	3-HR ROLLING AVERAGE	BACT-PSD	0			0		
OH-0363	NTE OHIO, LLC		OH	P0116610	221112	11/05/2014 ACT	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	Nitrogen Oxides (NOx)	Ultra low NOx burner	1.65	LB/H		BACT-PSD	3.3	T/YR	PER ROLLING 12 MONTH PERIOD	0.011	LB/MMBTU	
TX-0712	TRINIDAD GENERATING FACILITY	SOUTHERN POWER COMPANY	TX	111393 PSDTX1368	221112	11/20/2014 ACT	Southern Power Company (SPC) is proposing to construct an electric generating facility near Trinidad, Henderson County, Texas. The Trinidad Generating Facility (TGF) will include a natural gas-fired combined cycle combustion turbine generator (CTG) equipped with	boiler	natural gas	110	MMBTU/H	Nitrogen Oxides (NOx)	ultra-low NOx burners, limited use	9	PPMVD	@15% O2	BACT-PSD	0			0		
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	MOUNDSVILLE POWER, LLC	WV	R14-0030	221112	11/21/2014 ACT	Nominal 549 mW(output) natural gas-fired combined cycle power plant.	Auxiliary Boiler	Natural Gas	100	mmBtu/hr	Nitrogen Oxides (NOx)	Ultra Low-NOx Burners, Flue-Gas Recirculation, & Good Combustion Practices	2	LB/H		BACT-PSD	0			0.02	LB/MMBTU	
TX-0731	CORPUS CHRISTI TERMINAL CONDENSATE SPLITTER	MAGELLAN PROCESSING LP	TX	118270 AND PSDTX1398	324110	04/10/2015 ACT	100 MBpd topping refinery	Industrial-Size Boilers/Furnaces	natural gas	0		Nitrogen Oxides (NOx)	Selective catalytic reduction (SCR)	0.006	LB/MMBTU	12-MONTH AVG	BACT-PSD	0.01	LB/MMBTU	BLOCK 1-HR AVG	0		
CA-1206	STOCKTON COGEN COMPANY	APMC STOCKTON COGEN	CA	SJ 85-04	221112	09/16/2011 ACT	49.9 MW COGENERATION POWER PLANT OWNED BY AIR PRODUCTS MANUFACTURING CORPORATION (APMC) STOCKTON COGEN AND LOCATED IN STOCKTON, CALIFORNIA	AUXILIARY BOILER	NATURAL GAS	178	MMBTU/H	Nitrogen Oxides (NOx)		7	PPMVD	@3% O2	BACT-PSD	0.0085	LB/MMBTU		0		
CA-1212	PALMDALE HYBRID POWER PROJECT	CITY OF PALMDALE	CA	SE 09-01	221112	10/18/2011 ACT	570 MW NATURAL GAS FIRED COMBINED CYCLE POWER PLANT WITH AN INTEGRATED 50 MW SOLAR THERMAL PLANT	AUXILIARY BOILER	NATURAL GAS	110	MMBTU/H	Nitrogen Oxides (NOx)		9	PPMVD	@3% O2, 3-HR AVG	BACT-PSD	0			0		
OH-0336	CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	P0106678	311422	12/14/2010 ACT	Canned food maufacturing facility.	Boilers (3)	Natural Gas	0		Nitrogen Oxides (NOx)		0.04	LB/MMBTU	BASED ON MFG. GUARANTEE	OTHER CASE-BY-CASE	63.08	T/YR	ROLLING 12 MO. FROM 3 BOILERS TOGETHER	0		

Appendix C.1

Boiler #1 Cost Calculations for NO_X Control (SCR)

Boise - International Falls, MN

#1 Boiler

NO_X SNCR Calculations

	Boiler 1		Comment
Max Firing Rate	398	MMBtu/hr	PTE Calculations for Boiler 1.
NO_X Emission Rate (Uncontrolled)	0.1310	lb/MMBtu	Air emission inventory (see "Data Inputs")
NO_X Controls Emission Rate	0.0622	lb/MMBtu	Target (see "Data Inputs")
System Capacity Factor (Actuall rate vs. max firing rate at 8760)	39.8%		Actual fuel per year / Maxium fuel per year (See "SNCR Design Parameters")
Uncontrolled Emissions	90.9	ton/year	Calculated from Above
Control Efficiency	53%		Based on target emission rate above (mid-point of pulp and paper in Table 1.2)
Controlled Emissions	43.2	ton/year	Calculated from Above
Total Capital Investment (TCI)	$4,228,677		From "Cost Estimate"
Total Annual Cost (TAC) =	$475,742	per year in 2020 dollars	From "Cost Estimate"
NOx Removed =	47.7	tons/year	From "Cost Estimate"
Cost Effectiveness =	$9,969	per ton of NOx removed in 2020 dollars	From "Cost Estimate"

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.6

What type of fuel does the unit burn? Natural Gas

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 398.0 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,020 Btu/scf

What is the estimated actual annual fuel consumption? 1,414,842,703 scf/year

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR}) 351 days

Plant Elevation 1129 Feet above sea level

Inlet NO_x Emissions (NOx_{in}) to SNCR	0.131	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.06	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.22	

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	50	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
	Urea ▼	

Densities of typical SNCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Enter the cost data for the proposed SNCR:

Desired dollar-year	2020			
CEPCI for 2020	592.1	Enter the CEPCI value for 2020	541.7	2016 CEPCI
Annual Interest Rate (i)	5.5	Percent*		
Fuel ($Cost_{fuel}$)	2.13	\$/MMBtu		
Reagent ($Cost_{reag}$)	1.81	\$/gallon for a 50 percent solution of urea		
Water ($Cost_{water}$)	0.0051	\$/gallon		
Electricity ($Cost_{elect}$)	0.0676	\$/kWh*		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		\$/ton		

CEPCI = Chemical Engineering Plant Cost Index

* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) = 0.015

Administrative Charges Factor (ACF) = 0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost (\$/gallon)	\$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6, Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	

Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/MMBtu)	2.87	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Ash Disposal Cost ($/ton)	-	Not applicable	Not Applicable
Percent sulfur content for Coal (% weight)	-	Not applicable	Not Applicable
Percent ash content for Coal (% weight)	-	Not applicable	Not Applicable
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Interest Rate (%)	5.5	Default bank prime rate	

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	398	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	3,418,117,647	scf/year	
Actual Annual fuel consumption (Mactual) =		1,414,842,703	scf/year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.40	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	3487	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	53	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	27.37	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	47.72	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	(%S/100)x(64/32)*(1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.04		
Atmospheric pressure at 1129 feet above sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.1	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.60		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used: Urea

Molecular Weight of Reagent (MW) = 60.06 g/mole

Density = 71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	42	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/C_{sol} =	83	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	8.7	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	3,000	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0837

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	3.6	kW/hour
Water Usage: Water consumption (q_w) =	$(m_{sol}/\text{Density of water}) \times ((C_{stored}/C_{inj}) - 1)$ =	0	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	0.04	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1x10^6)/HHV$ =	0.0	lb/hour

Not applicable - Ash disposal cost applies only to coal-fired boilers

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$1,257,491 in 2020 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2020 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,995,337 in 2020 dollars
Total Capital Investment (TCI) =	$4,228,677 in 2020 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$1,257,491 in 2020 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2020 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$1,995,337 in 2020 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$119,899	in 2020 dollars
Indirect Annual Costs (IDAC) =	$355,843	in 2020 dollars
Total annual costs (TAC) = DAC + IDAC	$475,742	in 2020 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$63,430	in 2020 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$55,332	in 2020 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$859	in 2020 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$0	in 2020 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$277	in 2020 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2020 dollars
Direct Annual Cost =		$119,899	in 2020 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$1,903	in 2020 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$353,940	in 2020 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$355,843	in 2020 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$475,742	per year in 2020 dollars
NOx Removed =	48	tons/year
Cost Effectiveness =	$9,969	per ton of NOx removed in 2020 dollars

Table 1.2: SNCR NO_x Reduction Efficiency by Industry and Reagent Type [2, 4]

Industry and Units	% Reduction	
	Ammonia-Based	Urea-Based
Cement Kilns	12-77	25–90
Chemical Industry	NA[a]	35–80
Circulating Fluidized and Bubbling Bed Boilers	76–80	NA
Coal, Wood and Tire Fired Industrial and IPP/Co-Generations Boilers	NA	20–75
Coal-Fired Boilers	38–83	20–66
Gas- and Oil-Fired Industrial Boilers	30–75	NA
Glass Melting Furnaces	51–70	NA
Steel Products Industry	NA	42.9–90
Municipal Waste Combustors	45-70	16–87
Oil- and Gas-Fired Heaters	45–76	NA
Process Units	NA	40–85
Pulp and Paper Industry	NA	20–62
Refinery Process Units and Industrial Boilers	NA	20–75
Stoker-Fired and Pulverized Coal-Fired Boilers	50–83	NA
Stoker-Fired Wood-Fueled Boilers	40–75	NA
Vapor, Sludge and Hazardous Waste Incinerators	65–91	NA

[a] NA means not available.

Appendix C.2

Boiler #1 Cost Calculations for NO_X Control (LNB with FGR and OFA)

Low-NOx Burner (LNB) with Flue Gas Recirculation (FGR) and Overfire Air (OFA) Cost Estimate for Boise Paper LLC
Jun 23, 2020

As we talked on last Monday with a few assumptions, this is a high level estimate to support your order of magnitude request:

- General comments:
    - With your described emissions requirements we expect need of FGR to obtain the NOx limits. Unit operating data and a study/test could confirm this need.
    - Budget pricing is not an offer to sell.
    - Estimate is based on past work, future interface with sub vendors could be impacted by COVID 19 issues, or other business impacting conditions,
        - Examples, but not limited to (all of which could impact price and lead time)
            - price impacts (raw materials costs, labor rates…),
            - vendors out of business,
            - transportation disruptions,
            - manufacturing disruptions.
    - Asbestos mitigation is not considered in estimate and could be considerable if abatement is necessary.
    - Lead paint abatement is also not considered in estimate and also could be significant impact to cost.
    - Past installations were reviewed to accommodate best installation designs. With description of site and no drawings, budget price could be impacted due to unknown routing/obstructions.
    - No modifications are considered to radiant or convective heating surface or temperature control of final steam conditions.

- Scope boundaries would be:
    - Gas at inlet/outlet to main gas skid (not sure of your gas piping into the mill or capacity)
    - Gas at inlet/outlet to individual burners gas skids
    - Electrical at fan (no supply of electrical- BUS/Breakers wiring to fan, etc.)
    - Controls (no hardware/software for control system). Subs to supply logic for combustion control, and burner management
    - Existing windbox with modifications; repairs to existing windbox are not considered (physical conditions need to be evaluated)
    - FGR fan – conceptual ducting (this is a wildcard based on unfamiliar – described difficult routing)
- Base scope would typically include:
    - Engineering
    - T – fired burner gas/air buckets/lighters scope
    - Overfire air scope (assume FGR/COFA due to short furnace)
    - Gas skids
        - Main gas header valve train
        - Header vent spool
        - Burner gas valve train (one per burner)
        - Main flame scanners
    - FGR fan
    - FGR flue/dampers

- Other scope not supplied includes:
    - Field Service.
        - Installation, demolition, field testing, or construction management of the proposed equipment.
        - Load analysis of existing structural steel or any required re-enforcement
        - Engineering, Material, or Installation of any required modifications to existing structural support steel to accommodate new burner access platform addition if required, fan platform, valve rack supports or piping supports.
        - Modifications to the Combustion control system (DCS) software, configuration, review of existing loop diagrams, etc.
        - Modifications to the Combustion control system (DCS) equipment such as IO cards or other hardware necessary for the system to accept the new proposed burner and ignitor equipment.
        - Wiring design or material supply including site specific wiring diagrams, loop sheets, interconnection drawings, raceway layout drawings, wire, conduit, or cable trays.
        - Permits, licenses, and other Governmental Agency permission required to construct and operate the proposed equipment.
        - Spare or replacement parts.
        - Federal, state, or local sales and use taxes.
        - Baseline or Acceptance testing.
        - Damper control logic changes (if required).
        - Fees associated with any onsite approval agencies.
        - Boise Inc. to provide natural gas regulated to approximately 100 to 150 psig to the gas header inlet, with a maximum design pressure of 200 psig.
        - Fuel/Air piping beyond supplied valve racks (piping supply to main header valve rack, piping between valve racks or to/from burners and local valve racks).
        - Vent piping from valve racks to atmosphere.
        - Training Manual & Training.
        - Existing Primary Outlet header (temperature monitoring recommended).
        - Modifications to FD or ID fans.
        - Windbox interior compartment plates, windbox modifications or any repair or refurbishment which will be by others.
- Installation is based on a high level factor estimate and is subject to the above factors.

Pricing:

- Material $3.5M (see above)
- Installation $5M
    - General mechanical
    - Electrical
    - Piping
    - Controls (swag – based on no information available to understand existing)

Schedule:

Based on historic information a typical project span from receipt of order to delivery of equipment could be roughly 40-50 weeks. Thus added time for purchasing process along with staging materials and installation could add approximately 20 -30 weeks.

Other developmental cost typically provided by an Architectural Engineering firm and/or others are not included and could be required to support balance of plant aspects of this project. This could include but is not limited to:

- Controls integration of new equipment (factors of available space in existing electrical system and I/O points in control system for example)
- Stack monitoring equipment or data management systems for new emission reporting
- Structural aspect of new equipment integrated into the existing steel.
- Instrument air requirements as taxed to existing systems
- Existing equipment conditions (integration of new systems into old equipment can require significant investment to improve conditions of existing equipment to support intended integration of the new systems if existing is damaged or modified).

Boise - International Falls, MN

#1 Boiler

Table 1: LNB-FGR Summary

	Boiler 1		Comment
Max Firing Rate	398	MMBtu/hr	PTE Calculations for Boiler 1
NO_X Emission Rate (Uncontrolled)	0.131	lb/MMBtu	2019 Air emission inventory (see Table 2)
NO_X Controls Emission Rate	0.050	lb/MMBtu	Target
Utilization Rate	41.4%		2019 Air emission inventory (see Table 2)
Uncontrolled Emissions	90.9	ton/year	Calculated from Above
Control Efficiency	62%		Calculated from Above
Controlled Emissions	34.7	ton/year	Calculated from Above
Total Capital Investment (TCI)	$11,144,531		From Table 3 - NOx Control - LNB with FGR
Total Annual Cost (TAC) =	$1,557,544	per year in 2020 dollars	From Table 3 - NOx Control - LNB with FGR
NOx Removed =	56.2	tons/year	Calculated from Above
Cost Effectiveness =	$27,707	per ton of NOx removed in 2020 dollars	Calculated from Above

Boise White Paper LLC
International Falls, MN
Table 2: Summary of Utility, Chemical, and Supply Costs

Operating Unit:	Boiler 1	**Study Year**	2020
Emission Unit Number	EQUI17		
Stack/Vent Number	STRU25		

Boise International Falls Site Specific Data
EPA Default Scaled Value or Other Public Source
Other Barr Project (public or not client specific)

Item	2020 Unit Cost	Units	Cost	Year	Data Source	Notes
Operating Labor	67.53	$/hr	60	2016	EPA SCR Cost Manual Spreadsheet	
Maintenance Labor	67.53	$/hr				Assumed to be equivalent to operating labor
Installation Labor	67.53	$/hr				Assumed to be equivalent to operating labor
Electricity	0.08	$/kwh			2015-2019 EIA Average prices for the commerical sector	
Natural Gas	3.90	$/kscf			2015-2019 EIA Average prices for the commerical sector	
Water	0.42	$/mgal	0.20	1995	Hbbing Taconite BART 2006 Study	
Cooling Water	0.42	$/mgal	0.23	1999	Hbbing Taconite BART 2006 Study	
Compressed Air	0.48	$/kscf	0.38	2012	Taconite FIP Docket - Control cost estimate for UTAC	
Chemicals & Supplies						
Lime	183.68	$/ton	145.00	2012	Taconite FIP Docket - Control cost estimate for UTAC	
Trona	285.00	$/ton			Reagent cost for trona from another Barr Engineering Co. Project.	
Urea 50% Solution	1.81	$/gallon	1.66	2017	EPA SCR Cost Manual Spreadsheet	
Estimated operating life of the catalyst ($H_{catalyst}$)	20,000	hours			EPA Control Cost Manual for SCR suggests 16,000 - 24,000 hours	
SCR Catalyst cost ($CC_{replace}$)	255	$/cubic foot	227	2016	EPA SCR Cost Manual Spreadsheet	Cost includes removal and disposal/regeneration of existing catalyst and installation of new catalyst
Fabric Filter Bags	228.02	$/bag	180	2012	Taconite FIP Docket - Control cost estimate for UTAC	
Other						
Sales Tax	6.875%			2020	Tax Foundation Sales Tax as of 1/1/2019	Minnesota specific sales tax, not including local tax
Interest Rate	5.50%			2016	EPA SCR Cost Manual Spreadsheet	
Solid Waste Disposal	63.34	$/ton	50	2012	Taconite FIP Docket - Control cost estimate for UTAC	
Contingencies	10%	of purchased equip cost (B)			EPA Cost Control Cost Manual Chapter 2	Suggested contingency range of 5% to 15% of total capital investment
Markup on capital investment (retrofit factor)	25%				EPA Cost Control Cost Manual Chapter 2	Use retrofit factor of 25% (add 25% to installation cost to account for items not Covered by vendor cost estimate such as (1) Structural aspect of new equipment integrated into the existing steel. and (2) Existing equipment conditions (integration of new systems into old equipment can require significant investment to improve conditions of existing equipment to support intended integration of the new systems if existing is damaged or modified).)
Operating Information						
Annual Op. Hrs	8,424	Hours			2019 Operating Data	
Utilization Rate	41.4%				Assumed	
Design Capacity	398.0	MMBTU/hr			PTE Calculations for Boiler 9	
Equipment Life	20	yrs			Assumed	
Temperature	370	Deg F			SMBSC CEMs Stack Temperature Data	2018-2020 Average, excluding periods of boiler shutdown/startup
Moisture Content	11.8%				2014 Boiler 1 Hg Stack Test Data	
Actual Flow Rate	209,000	acfm			2014 Boiler 1 Hg Stack Test Data	
Standardized Flow Rate	132,954	scfm @ 68º F	123,889	scfm @ 32º F	Calculated Value	
Dry Std Flow Rate	117,332	dscfm @ 68º F			Calculated Value	
Fuel higher heating value (HHV)	1,020	btu/scf			Standard value	
Plant Elevation	1,100	Feet above sea level				International Falls, MN elevation
# days boiler operates	351	days			2019 AEI	
	Baseline Emissions					
Pollutant	**Lb/Hr**	**Ton/Year**			**Unit: lb/mmbtu**	
Nitrous Oxides (NOx)	21.6	90.9			0.131	2019 CEMS lb/MMBtu average. Use "utlization rate" to adjust to match ton/year from emission inventory

Boise White Paper LLC
International Falls, MN
Table 3 NO$_x$ Control - Low NOx Burners (LNB) with Flue Gas Recirculation (FGR)

Operating Unit: **Boiler 1**

Emission Unit Number	EQUI17		Stack/Vent Number	STRU25	
Desgin Capacity	398	MMBtu/hr	Standardized Flow Rate	123,889	scfm @ 32º F
Expected Utiliztion Rate	41%		Temperature	370	Deg F
Expected Annual Hours of Operation	8,424	Hours	Moisture Content	11.8%	
Annual Interest Rate	5.5%		Actual Flow Rate	209,000	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	132,954	scfm @ 68º F
			Dry Std Flow Rate	117,332	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)		Vendor provided cost estimate						**3,500,000.00**
Purchased Equipment Total (B)	11.9%	increase to control device cost (A) to include MN Sales Tax and Freight						**3,915,625.00**
Installation - Standard Costs		Vendor provided cost estimate						5,000,000.00
Installation - Site Specific Costs								0.00
Installation Total								5,000,000.00
Total Direct Capital Cost, DC								8,915,625.00
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)						0.00
Total Capital Investment (TCI) with retrofit factor = (DC + IC) * (1 + retrofit factor)	25%	retrofit factor to account for issues not addressed by vendor such as structural steel, condition of existing equipment, asbestos, etc.						**11,144,531.25**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						111,997.69
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						1,445,546.77
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**1,557,544.47**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Cont. Emis. lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrous Oxides (NOx)	90.9	19.9	**0.05**	34.7	56.2	27,707

Notes & Assumptions

1 Total installed capital cost estimate from vendor

2 Assumed 0.5 hr/shift operatior and maintenance labor for LNB

3 Controlled emission factor based on vendor estimated burner/OFA performance

4 Installation costs do not account for the following:
- Controls integration of new equipment (factors of available space in existing electrical system and I/O points in control system for example)
- Stack monitoring equipment or data management systems for new emission reporting
- Instrument air requirements as taxed to existing systems
- Permits, licenses, and other Governmental Agency permission required to construct and operate the proposed equipment.

Boise White Paper LLC
International Falls, MN
Table 3 NOx Control - Low NOx Burners (LNB) with Flue Gas Recirculation (FGR)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)		Vendor provided cost estimate	**$3,500,000.00**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation		Costs included in vendor provided estimate	$0.00
MN Sales Taxes	6.9%	of control device cost (A)	$240,625.00
Freight	5%	of control device cost (A)	$175,000.00
Purchased Equipment Total (B)	12%		**$3,915,625.00**
Installation [1]			
Foundations & supports			$0.00
Handling & erection			$0.00
Electrical			$0.00
Piping			$0.00
Insulation			$0.00
Painting			$0.00
Installation Total		Vendor provided cost estimate	**$5,000,000.00**
Installation Total			**$5,000,000.00**
Total Direct Capital Cost, DC			**$8,915,625.00**
Indirect Capital Costs			
Engineering, supervision	0%	Costs included in vendor provided estimate	$0.00
Construction & field expenses	0%	Costs included in vendor provided estimate	$0.00
Contractor fees	0%	Costs included in vendor provided estimate	$0.00
Start-up	0%	Costs included in vendor provided estimate	$0.00
Performance test	0%	Costs included in vendor provided estimate	$0.00
Model Studies	0%	Costs included in vendor provided estimate	$0.00
Contingencies	0%	Costs included in vendor provided estimate	$0.00
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)	**$0.00**
Total Capital Investment (TCI) = DC + IC			**$8,915,625.00**
Site Preparation, as required		Site Specific (see retrofit factor)	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific (see retrofit factor)	
Total Site Specific Costs			**$0.00**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**$8,915,625.00**
Total Capital Investment (TCI) with Retrofit Factor	25%	retrofit factor to account for issues not addressed by vendor such as structural steel, condition of existing equipment, asbestos, etc.	**$11,144,531.25**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	67.53	$/Hr, 0.5 hr/8 hr shift, 8424 hr/yr	$35,554.82
Supervisor	15%	15% of Operator Costs	$5,333.22
Maintenance (2)			
Maintenance Labor	67.53	$/Hr, 0.5 hr/8 hr shift, 8424 hr/yr	$35,554.82
Maintenance Materials	100%	of maintenance labor costs	$35,554.82
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
Total Annual Direct Operating Costs			**$111,997.69**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	$67,198.62
Administration (2% total capital costs)	2%	of total capital costs (TCI)	$222,890.63
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	$111,445.31
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	$111,445.31
Capital Recovery	8%	for a 20- year equipment life and a 5.5% interest rate	$932,566.91
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**$1,445,546.77**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**$1,557,544.47**

Boise White Paper LLC
International Falls, MN
Table 3 NOx Control - Low NOx Burners (LNB) with Flue Gas Recirculation (FGR)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:
N/A

Replacement Parts & Equipment:
N/A

Electrical Use

Reagent Use & Other Operating Costs

Operating Cost Calculations	**Annual hours of operation:**	**8,424**
	Utilization Rate:	**41%**

Regional Haze Four-Factor Analysis

Boiler #1 (EQUI 15 / EU 420)
Boiler #2 (EQUI 16 / EU 430)
Recovery Furnace (EQUI 9 / EU 320)

Prepared for
Boise White Paper LLC

Originally submitted July 15, 2020

Resubmitted on May 20, 2021 - includes corrected Appendix C.1 and added Appendix D, with no other changes to the original report.

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Regional Haze Four-Factor Analysis

July 15, 2020

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1 Executive Summary

On January 29, 2020 the Minnesota Pollution Control Agency's (MPCA's) submitted a Request for Information (RFI)[1] to Boise Paper LLC (Boise) regarding an analysis of emission reductions to support the development of the State Implementation Plan (SIP) for the Regional Haze Rule (RHR)[2]. The RFI requested that the facility evaluate potential emissions reduction measures for sulfur dioxide (SO_2) and nitrogen oxides (NO_X) for Boiler #2 (EQUI 16 / EU430), Recovery Furnace (EQUI 9 / EU 320), and for NO_X only for Boiler #1 (EQUI 15 / EU 420). The request said that the analysis must address the four statutory factors laid out in 40 CFR 51.308(f)(2)(i) and pursuant to the final U.S. Environmental Protection Agency (EPA) RHR State Implementation Plan (SIP) guidance[3] (2019 SIP Guidance):

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

The 2019 SIP Guidance was reviewed to determine if either Boiler #2 or Recovery Furnace were "effectively controlled" sources. Appendix A.1 demonstrates that Boiler #2 and Recovery Furnace are "effectively controlled" and does not need to conduct a four-factor analysis for those emission units as required in the January 29, 2020 RFI letter. Concurrence of this demonstration was provided by Hassan Bouchareb on May 29, 2020, which is included as in Appendix A.2.

This report evaluates potential NO_X control technologies and feasibility for Boiler #1, as required in the January 29, 2020 RFI. Boise has concluded that new emission controls are not warranted because the cost of compliance of technically feasible retrofit emission control technologies is not cost effective. As such, Boise proposes to maintain the existing NO_X permit limits for Boiler #1 as presented in Table 2-2.

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[1] January 29, 2020 letter from Hassan Bouchareb of MPCA to Boise Paper LLC.

[2] The U.S. Environmental Protection Agency (EPA) also refers to this regulation as the Clean Air Visibility Rule. The regional haze program requirements are promulgated at 40 CFR 51.308. The SIP requirements for this implementation period are specified in §51.308(f).

[3] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003.

2 Introduction

This section discussed the pertinent regulatory background information and a description of the emission sources at Boise which were identified by MPCA for analysis.

2.1 Four-factor Analysis Regulatory Background

The RHR published on July 15, 2005 by the EPA, defines regional haze as "visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources." The RHR requires state regulatory agencies to submit a series of SIPs in ten-year increments to protect visibility in certain national parks and wilderness areas, known as mandatory Federal Class I areas. Each SIP must be developed to make reasonable progress towards the ultimate goal of achieving natural background visibility by 2064. The initial SIPs, which were informed by best available retrofit technology (BART) analyses that were completed on all subject-to-BART sources, were due on December 17, 2007. The second RHR planning period requires development and submittal of updated state SIPs by July 31, 2021.

On January 29, 2020, the MPCA sent an RFI to Boise. The RFI stated that data from the Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring sites at Boundary Waters Canoe Area (BWCA) and Voyageurs National Park (Voyageurs) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of SO_2 and NO_X. In addition, emissions from sources in Minnesota could potentially impact Class I areas in nearby states, namely Isle Royale National Park (Isle Royale) in Michigan. Although Michigan is responsible for evaluating haze in Isle Royale, Michigan must consult with surrounding states, including Minnesota, on potential cross-state haze pollution impacts. As part of the planning process for the SIP development, MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to evaluate regional emission reductions.

The RFIs also stated that the facility was identified as a significant source of NO_X and SO_2 which is located close enough to the BWCA and Voyageurs to potentially cause or contribute to visibility impairment. Therefore, the MPCA requested that Boise submit a "four factors analysis" (herein termed as a four-factor analysis) by July 31, 2020 for the emission units identified in Table 2-1 as part of the State's regional haze reasonable progress.

Table 2-1 Identified Emission Units

Unit	Unit ID	Applicable Pollutants	Effectively Controlled[4]	Four Factor Analysis Required[5]
Boiler #1	EQUI 15 / EU 420	NO_X	Not Applicable	Yes
Boiler #2	EQUI 16 / EU 430	NO_X, SO_2	Yes	No
Recovery Furnace	EQUI 9 / EU 320	NO_X	Yes	No

The MPCA stated that the analysis must consider potential emissions reduction measures by addressing the four statutory factors which are laid out in 40 CFR 51.308(f)(2)(i):

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

The RFI letter to the Boise specified that the "analysis should be prepared using the U.S. Environmental Protection Agency guidance" referring to the final 2019 SIP Guidance.

This report describes the background and analysis for conducting a four-factor analysis for NO_X and SO_2 for the emission units identified in Table 2-1.

2.2 Emission Unit Description

Boise is wholly owned by Packaging Corporation of America (PCA). The facility in International Falls, Minnesota is an integrated kraft pulp and paper mill that produces commodity and specialty paper. The three emission units included in MPCA's RFI are:

- **Boiler #1 (EQUI 15):** This emission unit 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 (EQUI 24) 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.

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[4] See Section 2.3 Boiler #2 and Recovery Furnace: Effective Controls

[5] Four-Factor Analysis applicability for Boiler #2 and Recovery Furnace is included in Appendix A.1

- **Boiler #2 (EQUI 16):** This emission unit 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.

- **Recovery Furnace (EQUI 9):** 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 (H_2SO_4), 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 NO_X controls but does use staged air injection to manage the generation of NO_X.

2.3 Boiler #2 and Recovery Furnace: Effective Controls

The 2019 SIP Guidance states that it “may be reasonable for a state not to select an effectively controlled source”[6] for the four-factor analysis with the rationale that “it is reasonable to assume for the purposes of efficiency and prioritization that a full four-factor analysis would likely result in the conclusion that no further controls necessary.”[7] EPA identified potential scenarios that “EPA believes it may be reasonable for a state not to select a particular source for further analysis.” However, EPA clarified that the associated scenarios are not a comprehensive list but are merely to illustrate examples for the state to consider.

Boise submitted a letter to MPCA on May 8, 2020 requesting the RFI be withdrawn for Boiler #2 (EQUI 15) and the Recovery Furnace (EQUI 9) because these sources are already “effectively controlled” as defined in the 2019 SIP Guidance. MPCA responded via email on May 29, 2020 and confirmed that these sources are

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[6] US EPA, “Guidance on Regional Haze State Implementation Plans for the Second Implementation Period,” August 20, 2019, EPA-457/B-19-003, Page 22.

[7] Ibid, Page 23.

“effectively controlled,” and, therefore, a four-factor analysis is not required. Boise’s request letter and MPCA’s response email are presented in Appendix A.1 and Appendix A.2, respectively.

2.4 Boiler #1: Permit Limits

Boise’s current Title V Operating Permit #01700002-101 limits Boiler #1 NO_X emissions in Conditions 5.13.1-5.14.5. In addition, the emissions of NO_X from this source are also subject to the NO_X Cap Group limits as presented in Conditions 5.2.1-5.2.7. Boiler #1 does not have add-on NO_X controls but the generation of NO_X is managed by good combustion practices and NO_X emissions are measured by a continuous emission monitoring system (CEMS). The numeric emission limits are presented in Table 2-2. It is noteworthy that the individual NO_X emission limit is based on modeling and the NO_X Cap Group limits are based on a visibility impacts analysis. Additionally, the NOx modeling will soon be updated as the air permit Condition 6.1.10 states “The Permittee shall submit a computer dispersion modeling protocol for 1-hour and annual NO2 NAAQS due by 6/6/2021. This protocol will describe the proposed modeling methodology and input data, in accordance with the current version of the MPCA Air Dispersion Modeling Guidance.”

Table 2-2 Boiler #1 (EQUI 15) Permit Limits

Pollutant	Condition	Limit	Basis of Limit
NO_X	5.14.3	Nitrogen Dioxide <= 0.20 pounds per million Btu heat input 30-day rolling average.	Title I Condition: 40 CFR 52.21(k) (modeling) & Minn. R. 7007.3000
NO_X	5.2.1	The Permittee shall limit emission of Nitrogen Oxides <= 3.67 tons per day from combustion sources (EQUI 9, EQUI 15, EQUI 16, EQUI 17, and EQUI 18).	Title I Condition: 40 CFR 52.21(o) (visibility) & Minn. R. 7007.3000
NO_X	5.2.3	The Permittee shall limit emissions of Nitrogen Oxides <= 4.18 tons per day. This limit is the total NOx cap for the combustion sources (Boilers #1, #2, #3, #9, and the recovery furnace) (EQUI 15, EQUI 16, EQUI 17, EQUI 18, EQUI 9, respectively) as well as the lime kiln and smelt dissolving tank (EQUI 13 and EQUI 945).	Title I Condition: 40 CFR 52.21(o) (visibility) & Minn. R. 7007.3000

3 Boiler #1: Four-factor Analysis for NO_X

This section identifies baseline emission rates and evaluates the four statutory factors for NO_X emissions from Boiler #1.

3.1 Emission Control Options

The 2019 SIP Guidance states that the "first step in characterizing control measures for a source is the identification of technically feasible control measures for those pollutants that contribute to visibility impairment."[8] However, EPA recognized that a "state must reasonably pick and justify the measures that it will consider, recognizing that there is no statutory or regulatory requirement to consider all technically feasible measures or any particular measures."[9] This section addresses the selection of emission control options for NO_X from Boiler #1.

The following methodology was used to determine which emission control technologies should be considered in the four-factor analysis:

1. Search the RACT/BACT/LAER Clearinghouse (RBLC)[10] for available control technologies with the following search criteria:
    - Similar emission unit type (process name)
    - Similar fuel
    - 10-year look back
2. Eliminate technologies that would not would not apply to the specific emission unit under consideration
3. Advance the remaining technologies for consideration in the four-factor analysis

The RBLC search for natural gas fueled boilers for NO_X is presented in Appendix B and a summary is provided in Table 3-1.

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[8] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003, page 28.

[9] Ibid, Page 29.

[10] RACT/BACT/LAER Clearinghouse (RBLC) as maintained by USEPA (link to RBLC website)

Table 3-1: Natural Gas Power Boiler RBLC Summary – NO_X

RBLC ID	Technology
TN-0162 TN-0164	Selective Catalytic Reduction Low NO_X Burners Flue Gas Recirculation
TX-0811	Selective Catalytic Reduction Low NO_X Burners
TX-0731	Selective Catalytic Reduction
IN-0179 WV-00025	Ultra Low NO_X Burners Flue Gas Recirculation
PA-0306 LA-0314 OH-0363 AK-0083 VA-0325 TX-0712	Ultra Low NO_X Burners
LA-0272 AR-0121 IN-0263 MI-0423 OH-0374	Low NO_X Burners Flue Gas Recirculation
MI-0427	Low NO_X Burners with internal (within the burner) Flue Gas Recirculation
LA-0307 TX-0641 VA-0328 OH-0354 TX-0708	Low NO_X Burners
TX-0576	Good Combustion Practice

Good combustion practices were not considered in the four-factor analysis because these are already implemented through a combination of several efforts, including control strategy, boiler monitoring, and training.

As shown in Table 3-1, the majority of the control technologies presented in the RBLC include LNB or ULNB, with or without FGR. The specific technology selected for these projects was likely dependent on the targeted emission rate. For the purposes of the four-factor analysis, Boise has combined these technologies into a single category titled "LNB/ULNB with or without FGR" and then contacted a vendor to provide a technically feasible solution for the target emission rate (additional detail is provided in Section 3.3).

Based on this information, the technologies that were considered in the four-factor analysis are:

- SCR
- LNB/ULNB with or without FGR

3.2 Baseline Emission Rates

The 2019 SIP Guidance states that the "projected 2028 (or the current) scenario can be a reasonable and convenient choice for use as the baseline control scenario for measuring the incremental effects of potential reasonable progress control measures on emissions, costs, visibility, and other factors."[11] Thus, Boise anticipates flat growth in the paper industry and projects that emissions in 2028 will be equivalent to 2019 actual emissions.

Table 3-2: Projected 2028 NO_X Emissions (tons per year)

Year	Boiler #1
2019 actual emissions	90.9 tons/year
2028 Projected Emissions	90.9 tons/year

3.3 Factor 1 – Cost of Compliance

Boise has completed compliance cost estimates for the selected NO_X emission control measures following EPA's Control Cost Manual as recommended in the 2019 SIP Guidance.[12] The SCR cost estimate were based on spreadsheet templates provided by EPA. The LNB/ULNB cost estimate is based on a vendor cost estimate for which the vendor was asked to provide a technically feasible solution to reduce emissions from the current emission rate (0.131 lb/MMBtu) to 0.050 lb/MMBtu which is the emission limit for Boise's Boiler #3 (EQUI 17) as shown in permit condition 5.16.1. The conceptual design provided by the vendor is LNB with FGR and over-fire air (OFA).

The capital cost estimates were confirmed by Boise's plant engineering staff as reasonable, based on their considerable experience with projects at Boise and their informal conversations with other companies that have completed similar types of projects at other facilities. A more detailed cost estimate is likely to increase the costs for installing and implementing either of the projects. Cost calculation spreadsheets for the NO_X emission control measures are provided in Appendix C.

The cost effectiveness analysis compares the annualized cost of the technology 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.

The resulting cost effectiveness calculations are summarized in Table 3-3.

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[11] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003, page 29.

[12] Ibid, Page 21.

Table 3-3: Boiler #1 NO_X Control Cost Summary, per Unit Basis

Additional Emissions Control Measure	Total Capital Investment ($)	Total Annualized Costs ($/year)	Control Efficiency (%)	Annual Emissions Reduction (tpy)	Pollution Control Cost Effectiveness ($/ton)
SCR	$7,828,245	$970,836	69%	63.1	$15,375
LNB with FGR and OFA	$11,144,531	$1,557,544	62.0%	56.2	$27,707

Based on the information provided in Table 3-3 and in consideration of RHR analyses conducted in other states, the emission control measures were not considered cost effective.

Sections 3.4 through 3.6 provide a screening-level summary of the remaining three factors evaluated for the NO_X emission control measures, understanding that these projects represent substantial capital investments that are not justified on a cost per ton or absolute cost basis.

3.4 Factor 2 – Time Necessary for Compliance

Factor #2 estimates the amount of time needed for full implementation of the different control measures. Typically, the time for compliance considers the time needed to develop and approve the new emissions limit into the SIP by state and federal action, then to implement the project necessary to meet the SIP limit via installation and tie-in of equipment for the emissions control measure.

The technologies would require significant resources and time of at least two to three years design, engineer, procure, and install the equipment. The facility would attempt to complete the construction during a regularly scheduled outage but recognizes that the outage may need to be extended to install all required equipment.

The SIP is scheduled to be submitted in 2021 with the anticipated approval in 2022 (approximately one year after submittal). Once the SIP is approved, the design, engineer, procurement, and installation schedule would begin. This would put the anticipated date of installation in 2024 or 2025.

3.5 Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance

The energy and non-air environmental impacts associated with implementation of the above identified NO_X control measures are summarized below.

- SCR
    - Increased truck and/or train traffic (reagent and catalyst deliveries)
    - Possible ammonia slip (unreacted reagent that is emitted to the atmosphere)
    - Catalyst regeneration
    - Catalyst disposal
    - Electricity consumption (fans and pumps)
- LNB with SCR and OFA
    - Electricity consumption (fans)
    - Possible increase in carbon monoxide (CO) emissions)

3.6 Factor 4 – Remaining Useful Life of the Source

Because Boiler #1 is expected to continue operations for the foreseeable future, the useful life of the individual control measures (assumed 20-year life) was used to calculate emission reductions, amortized costs, and cost effectiveness on a dollar per ton basis.

3.7 Proposed NO_X Controls and Emissions Rates

This four-factor analysis does not support the installation of additional NO_X emission control measures at Boiler #1 beyond those described in Section 2.3. As such, Boise proposes to maintain the existing NO_X permit limits presented in Table 2-2.

Appendices

Appendix A.1

Four-Factor Analysis Applicability

For Boiler #2 and Recovery Furnace

May 8, 2020

Hassan M. Bouchareb
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155-4194

Re: Request for Information – Regional Haze Rule, Reasonable Progress, Four-Factor Analysis

Dear Mr. Bouchareb:

This letter is in response to your January 29, 2020, request for information (RFI) to Boise White Paper LLC (Boise) regarding the Regional Haze Rule (RHR). The RFI requested that Boise submit a "four-factor analysis" of control equipment for three emission units at our International Falls facility. The analysis would be used by the Minnesota Pollution Control Agency (MPCA) to develop a comprehensive update to Minnesota's Regional Haze State Implementation Plan (SIP) as required by the RHR (40 CFR 51.308). The RFI stated that the analysis should be prepared following guidance[1] provided by the U. S. Environmental Protection Agency (EPA).

EPA's guidance recognizes that the states have flexibility in deciding which sources must conduct a four-factor analysis. For example, the guidance states that it "*may be reasonable for a state not to select an effectively controlled source*"[2] and that, for such sources, a state should explain "*why it is reasonable to assume for the purposes of efficiency and prioritization that a full four-factor analysis would likely result in the conclusion that no further controls are necessary.*"[3]

This letter requests that MPCA withdraw the RFI for the Recovery Furnace (EQUI 9 / EU 320) and Boiler #2 (EQUI 15 / EU 420) because these sources are already "effectively controlled" as defined in EPA's guidance[4]. The following supporting rationale explains why this determination is consistent with MPCA's requirement to make reasonable progress.

1 Background

The MPCA is required to develop and implement air quality protection plans to reduce pollution that causes haze at national parks and wilderness areas, known as Class I areas. The RHR requirements are found in 40 CFR 51.308. The state of Minnesota includes two Class I areas: Boundary Waters Canoe Area Wilderness (BWCAW) and Voyageurs National Park (Voyageurs). In addition, emissions from sources in Minnesota could potentially impact Class I areas in nearby states—namely, Isle Royale National Park

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[1] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019.

[2] Ibid, Page 22.

[3] Ibid, Page 23

[4] Ibid, Page 22.

(Isle Royale) in Michigan. Although Michigan is responsible for evaluating haze at Isle Royale, it must consult with surrounding states, including Minnesota, on potential cross-state haze pollution impacts.

The goal of the RHR is to return the Class I areas to natural visibility conditions by 2064. To that end, the RHR requires states to develop a state implementation plan (SIP) and to provide comprehensive updates every 10 years. MPCA submitted its Regional Haze SIP in December 2009, updated it in May 2012, and must submit a comprehensive update by July 31, 2021, to address reasonable progress in the second implementation period, 2018-2028. Progress is tracked by the EPA and the MPCA based on the IMPROVE (Interagency Monitoring of Protected Visual Environments) monitoring sites at the BWCAW (BOWA1), Voyageurs (VOYA2) and Isle Royale (ISLE1).

Each SIP revision is required to address several elements, including:

- Calculations of baseline, current, and natural visibility conditions; progress to date; and the uniform rate of progress (40 CFR 51.308(f)(1))
- Long-term strategy for regional haze (40 CFR 51.308(f)(2))
- Reasonable progress goals (40 CFR 51.308(f)(3))
- Monitoring strategy and other implementation plan requirements (40 CFR 51.308(f)(6))

On January 29, 2020, MPCA sent an RFI to Boise which stated that our facility was identified as a significant source of NO_X and SO_2 and is located close enough to the BWCAW or Voyageurs to potentially cause or contribute to visibility impairment in these Class I areas. Therefore, the MPCA requested that we submit a “four-factor analysis”[5] by July 31, 2020, for the emission units identified in Table 1.

Table 1: Identified Emission Units

Unit	Unit ID	Applicable Pollutants
Recovery Furnace	EQUI 9 / EU 320	NO_X
Boiler #1	EQUI 15 / EU 420	NO_X
Boiler #2	EQUI 16 / EU 430	NO_X, SO_2

The RFI stated that the “*analysis should be prepared using the U.S. Environmental Protection Agency guidance*[6] *that provides recommendations for how each of the factors should be determined*.” The results of the four-factor analysis would be incorporated into the long term strategy which must “*include the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress.*”[7]

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[5] The four factors are presented in 40 CFR 51.308(f)(2)(i): cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts of compliance and remaining useful life of the source.

[6] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[7] 40 CFR 51.308(f)(3)

The reasonable progress goals are determined based on several criteria, including an evaluation of the "*rate of progress needed to attain natural visibility conditions by the year 2064…. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction measures needed to achieve it for the period covered by the implementation plan.*"[8]

2 Current Visibility in BWCAW, Voyageurs, and Isle Royale

The data from the IMPROVE monitoring network for BWCAW, Voyageurs, and Isle Royale are available on MPCA's website[9]. As shown in figures 1 through 3, the visibility at each Class I area has been improving since 2009 and is already below the 2028 uniform rate of progress (URP)[10]. The observed visibility improvement could be attributed to emission reductions from regulated stationary sources due to a variety of reasons, including:

- installation of best available retrofit technology (BART) during the first RHR implementation period,
- emission reductions from a variety of industries, including the pulp and paper sources, due to updated rules and regulations, and
- transition of power generation systems from coal to natural gas and renewables (wind and solar).

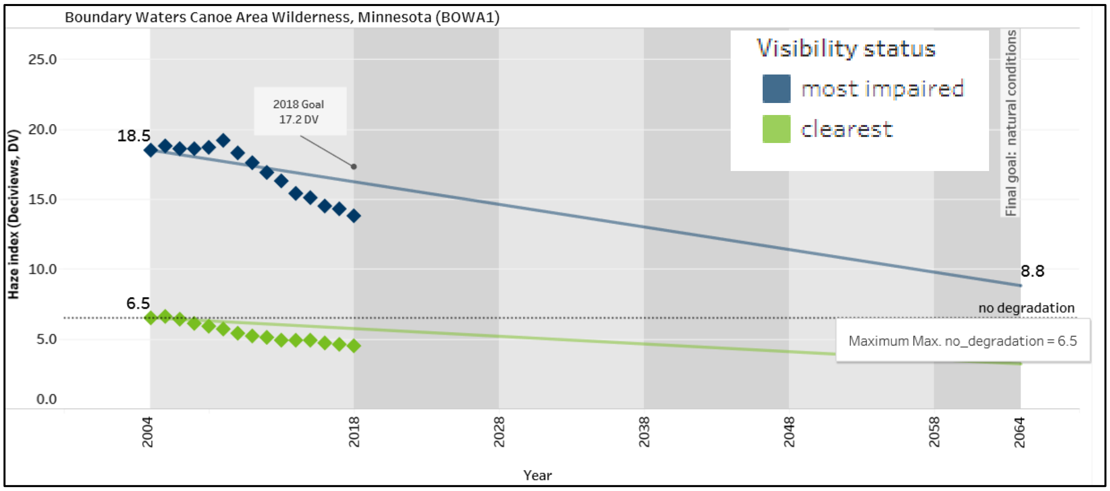

Figure 1: BWCAW Current Visibility Conditions

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[8] 40 CFR 51.308(d)(1)(i)(B)

[9] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

[10] The URP is determined based on the slope of the line from baseline conditions (2000-2004) to the natural visibility conditions in 2064

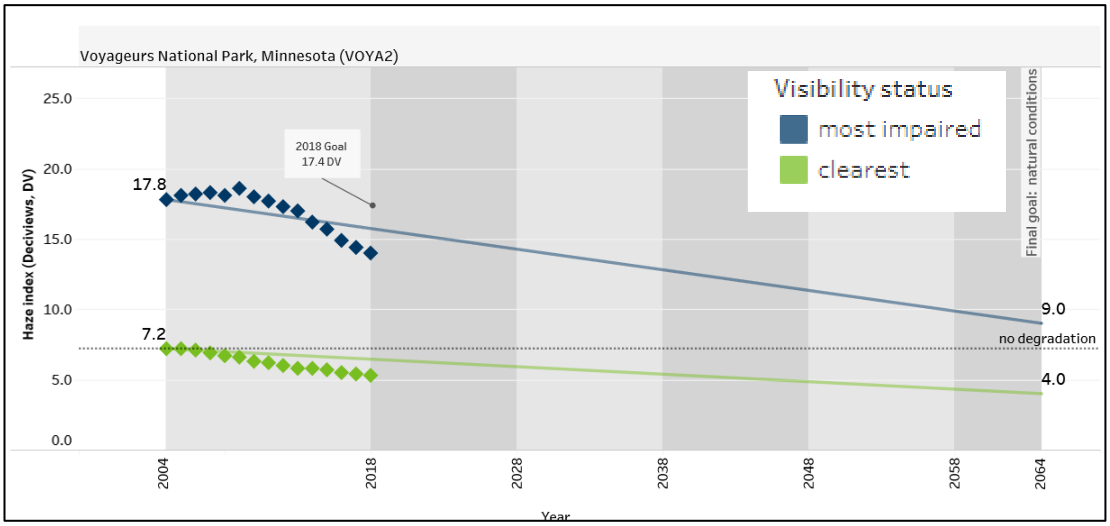

Figure 2: Voyageurs Current Visibility Conditions

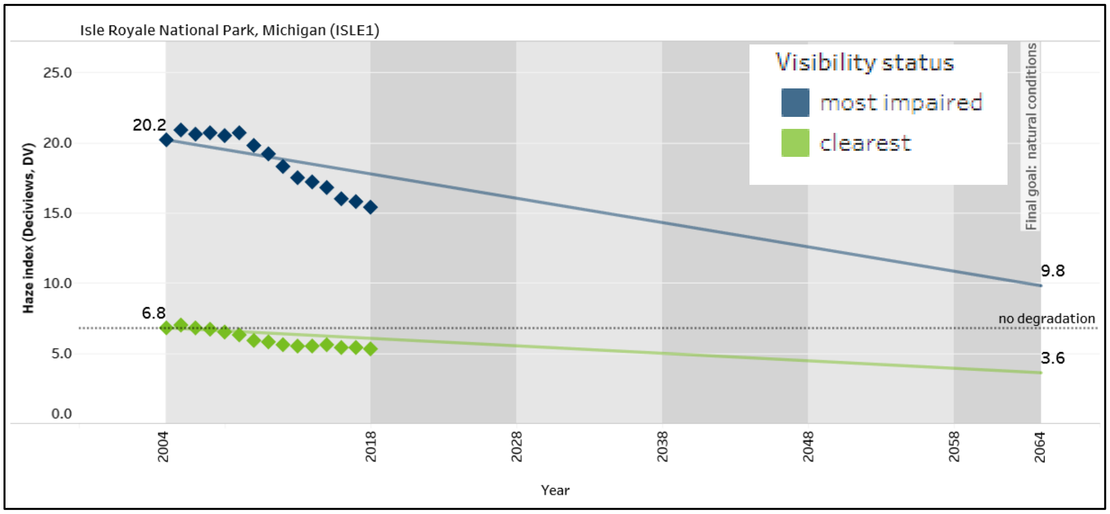

Figure 3: Isle Royale Current Visibility Conditions

Some of these emission reductions have recently occurred but are not fully reflected in the 5-year average monitoring data presented in figures 1 through 3. For example, Minnesota Power retired two coal-fired boilers at the Boswell Energy Center in Cohasset at the end of 2018. In addition, the compliance schedule is still in progress for the NO_X emission reductions required by the Taconite Federal Implementation Plan (FIP) Establishing BART for Taconite Plants (40 CFR 52.1235). Furthermore, there are others emission reduction projects that are scheduled to occur in Minnesota prior to 2028, the end of the second RHR implementation period (e.g., Xcel Energy boiler retirements as detailed in their Upper Midwest Integrated Resource Plan, 2020-2034). These emission reductions will further improve the visibility in the Class I areas.

3 EPA Guidance for State Implementation Plans

MPCA's January 29, 2020, RFI stated that the four-factor analysis should follow EPA's guidance[11] that provides recommendations for how each of the factors should be determined. Additionally, EPA also provides states guidance on selecting sources which must conduct a four-factor analysis.

The guidance says that the state will determine which emission control measures are necessary to make reasonable progress in the affected Class I areas[12]. However, as discussed in Section 2, the current sustained progress towards visibility goals in BWCAW, Voyageurs, and Isle Royale is such that the MPCA may tolerate the current reduction trajectory of emission reductions during the second implementation period. The MPCA would be warranted to further consider the flexibility allowed in the RHR to "*reasonably select a set of sources for an analysis of control measures.*"[13] The monitoring information will help MPCA "*explain why the decision is consistent with the requirement to make reasonable progress.*"[14]

4 EPA Guidance for Effectively Controlled Sources

EPA guidance states that it "may be reasonable for a state not to select an effectively controlled source"[15] for the four-factor analysis with the rationale that "*it is reasonable to assume for the purposes of efficiency and prioritization that a full four-factor analysis would likely result in the conclusion that no further controls necessary*."[16] EPA identified potential scenarios that "*EPA believes it may be reasonable for a state not to select a particular source for further analysis*." However, EPA clarified that the associated scenarios are not a comprehensive list but are merely to illustrate examples for the state to consider.

One of the "effectively controlled" scenarios is for sources that went through a best available control technology (BACT) review with a construction permit issued on or after July 31, 2013.[17] EPA notes that the BACT control equipment review methodologies are "*similar to, if not more stringent than, the four statutory factors for reasonable progress.*" As presented below, an extension of the BACT review scenario is for sources that have existing permit limits, independent of the statutory basis (e.g., air dispersion modeling, PSD avoidance limit, etc.), which are consistent or sufficiently similar to recent BACT determinations for similar sources. Because the limits are similar to BACT, this extension is consistent with EPA's conclusion that a four-factor analysis "*would likely result in the conclusion that no further controls are necessary.*"

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[11] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[12] Ibid, Page 9.

[13] Ibid.

[14] Ibid, Page 23.

[15] Ibid, Page 22.

[16] Ibid, Page 23.

[17] Ibid.

4.1 Recovery Furnace (EQUI 9 / EU 320)

The RFI requested a four-factor analysis for NO_X emissions from the Recovery Furnace which is a combustion unit that burns black liquor solids (BLS) from the Kraft pulping process to recover spent cooking chemicals. The combustion process generates heat which is recovered by steam generation. The combustion process results in NO_X and other emissions.

The Recovery Furnace has not undergone a NO_X BACT review since July 31, 2013, so this unit does not directly meet this scenario. However, the current NO_X limit[18] (100 lb/hr per 30-day rolling average, which is equivalent to 80 ppm at 8% oxygen (O_2)) was compared to recent determinations in EPA's RBLC database (Attachment A) and the limit is consistent with NO_X limits from recent BACT determinations (e.g., 85 ppm at 8% O_2[19], 120 ppm at 8% O_2[20]).

Because the current NO_X emission limit is similar to recent BACT determinations and BACT control equipment reviews are "*similar to if not more stringent than*" the four-factor analysis methodology, it is unlikely that additional controls would be available to further reduce emissions. Therefore, this unit is sufficiently similar BACT scenario and MPCA can justify that a four-factor analysis need not be completed.

4.2 Boiler #2 (EQUI 16 / EU 430)

The RFI requested a four-factor analysis for NO_X and SO_2 emissions Boiler #2 which is an industrial boiler that is permitted to burn the following fuels: [21]

- Biomass (commonly referred to as "hog fuel")
- WWTP Sludge
- Natural Gas
- Non-Condensable Gas (NCG)

The associated combustion results in NO_X and SO_2 emissions, among other emissions.

NO_X: Boiler #2's current NO_X limit[22] (100.2 lb/hr, which is equivalent to 0.25 lb/MMBtu at the maximum firing rate) was compared to recent determinations in EPA's RBLC database (Attachment B) and the limit is consistent with NO_X limits from recent BACT determinations (e.g., two determinations[23,24] with 0.3 lb/MMBtu limits).

Because the current NO_X emission limit is similar to recent BACT determinations and BACT control equipment reviews are "*similar to if not more stringent than*" the four-factor analysis methodology, it is unlikely that additional controls would be available to further reduce emissions. Therefore, this unit is

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[18] Title V Operating Permit (TVOP) Condition 5.13.7

[19] 2019 BACT determination for Sun Bio Materials Company (AR-0161)

[20] 2015 BACT determination for Rocktenn CP, LLC (AL-0302)

[21] Permit 07100002-014 Condition 5.17.14 limits fuel burned to "bark, wood refuse, wastewater treatment sludge, paper, and natural gas. Non-condensable gas (NCG) is also oxidized in Boiler #2."

[22] TVOP Condition 5.17.7

[23] 2010 BACT determination for Boise White Paper (AL-0250)

[24] 2014 BACT determination for Abengoa Bioenergy Biomass of Kansas (KS-0034)

sufficiently similar BACT scenario and MPCA can justify that a four-factor analysis need not be completed.

SO_2: When considering the SO2 emissions from Boiler #2, it is important to note:

- The primary fuel is hog fuel, a biomass which is primarily bark from the facility de-barking process. This fuel is inherently low in sulfur.
- Natural gas is a supplemental fuel and is also a low-sulfur fuel.
- Most of the SO_2 emissions from the boiler are a direct result of Non-Condensable Gas (NCG) combustion. However, Boiler #2 is the secondary NCG combustion source[25] and is only utilized when the primary NCG combustion source (Lime Kiln (EQUI 13 / EU 340)) is unavailable; Boiler #1 (EQUI 15 / EU 420) is the tertiary NCG combustion device[26].
- Boiler #2 has an SO_2 emission limit (9.4 lb/hr as a 12-hr rolling average, which is equivalent to 0.024 lb/MMBtu at the maximum firing rate) which applies when NCG is not being combusted.[27]
- Boiler #1 and Boiler #2 have a combined SO_2 emission limit (115 tons per rolling 12-month period) which applies when burning NCG in either of the backup combustion sources.[28]
- Maintaining the ability to combust the NCG in the backup combustion sources is part of the overall strategy for limiting emissions of hazardous air pollutants because 40 CFR Part 63 Subpart S (National Emission Standards for Hazardous Air Pollutants from the Pulp and Paper Industry) limits the amount of time that NCG can be vented to the atmosphere without combustion.
- Additionally, maintaining the ability to combust NCG in the backup combustion sources is an engineered control to maintain the continued safe operation of the Kraft pulping equipment and process.

Boiler #2's current SO_2 limit, which applies when NCG is not being combusted (9.4 lb/hr as a 12-hr rolling average, which is equivalent to 0.024 lb/MMBtu at the maximum firing rate)[29], was compared to recent determinations in EPA's RBLC database (Attachment C). The limit is consistent with SO_2 limits from recent BACT determinations for similar sources (e.g., 0.025 lb/MMBtu[30], 0.21 lb/MMBtu[31]).

The TVOP limits the SO_2 emissions from the backup NCG combustion sources (Boiler #1 and Boiler 2) to 115 tons per rolling 12-month period.[32] As stated above, maintaining the ability to combust the NCG in the backup combustion sources is part of the overall strategy for limiting emissions of hazardous air pollutants as required by 40 CFR Part 63 Subpart S. Boise works diligently to maintain the availability of the primary NCG combustion source (Lime Kiln) which limits the actual emissions from the facility. For

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[25] TVOP Condition 5.3.3
[26] Ibid.
[27] TVOP Condition 5.17.6
[28] TVOP Condition 5.3.6
[29] TVOP Condition 5.17.6
[30] 2019 BACT determination for Sun Bio Materials Company (AR-0161)
[31] 2014 BACT determination for Abengoa Bioenergy Biomass of Kansas (KS-0034)
[32] TVOP Condition 5.3.6

example, the maximum annual SO_2 emissions from Boiler #2 in the past five years was 35.4 tons which resulted from 436 hours (18.2 days) of NCG combustion. Although the actual emissions provide for a large margin of compliance, Boise could not take a more stringent limit because the existing limit could be necessary if an unanticipated downtime or failure of the primary combustion source were to occur.

In regards to the installation of SO_2 controls on Boiler #2 for the NCG combustion scenario, it is unlikely that any controls would be cost effective. This conclusion is based on designing the SO_2 controls to treat the full volume of Boiler #2 flue gas (i.e., a large annualized capital expenditure) but only operating the equipment when NCG is being combusted (e.g., the maximum SO_2 emissions from Boiler #2 in the past five years resulted from 18.2 days of NCG combustion). The annualized cost will be high but the low utilization of the control equipment will not result in large actual emission reductions and the cost would therefore not be cost-effective.

The SO_2 emission limit when NCG is not being combusted is similar to recent BACT determinations and BACT control equipment reviews are "*similar to if not more stringent than*" the four-factor analysis methodology, it is unlikely that additional controls would be available to further reduce emissions. In addition, the SO_2 emission limit when NCG is being burned is necessary for the backup combustion sources to ensure control of HAP emissions but the installation of control equipment to operate only when combustion NCG would not be cost effective. Therefore, the MPCA can justify that a four-factor analysis need not be completed.

5 Conclusion

As described in Section 2, the current visibility in the nearby Class I areas is already below the 2028 glidepath, so MPCA does not need to consider an excessive reasonable progress goal for the SIP revision that is due in 2021. Furthermore, as described in Section 4, there is sufficient justification to consider the Recovery Furnace and Boiler #2 as "effectively controlled" sources. Thus, it "*may be reasonable for a state not to select an effectively controlled source*" to conduct a four-factor analysis because "*there will be only a low likelihood of a significant technological advancement that could provide further reasonable emission reductions*."[33] Therefore, Boise requests that your RFI dated January 29, 2020, be withdrawn for the Recovery Furnace and Boiler #2. We will continue to proceed with a four factor analysis for Boiler #1 as directed in the RFI dated January 29, 2020.

We are available at your convenience to discuss this request in detail. Please advise if a telephone conference is desired. You may contact Kara Huziak at karahuziak@boisepaper.com with questions or to request a meeting.

Thank you for considering our request.

Sincerely,

Mike Wagner
Mill Manager

Attachments:

A. RBLC Summary: NO_X from Recovery Furnaces
B. RLBC Summary: NO_X from Hog Fuel Boilers
C. RBLC Summary: SO_2 from Hog Fuel Boilers

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[33] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, Page 23.

Boise White Paper LLC
Regional Haze "Effectively Controlled" Source Scenario Comparison Analysis
Attachment A: Recovery Furnace NOx RBLC Search

Pollutant Name: NOx

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
AL-0266	GEORGIA PACIFIC BREWTON LLC	GEORGIA PACIFIC LLC	AL	502-0001-X044	322130	06/11/2014 ACT	Kraft Pulp & Paper mdu	No.4 Recovery & Smelt Tank	Black Liquor	1355	MMBTU/ hr	Nitrogen Oxides (NOx)	Staged air combustion	90	PPM@8%O2	3HRS AVG	BACT-PSD	221	LB/H	3HRS AVG	0		
AL-0266	GEORGIA PACIFIC BREWTON LLC	GEORGIA PACIFIC LLC	AL	502-0001-X044	322130	06/11/2014 ACT	Kraft Pulp & Paper mdu	No. 4 REC & Smelt	Natural Gas	1355	mmbtu	Nitrogen Oxides (NOx)	Gas Combustion	0.2	LB/MMBTU	3 HRS AVG	BACT-PSD	145.12	LB/H	3 HRS AVG	0		
AL-0274	BOISE WHITE PAPER, LLC	BOISE WHITE PAPER, LLC	AL	102-0001-X011	322121	02/04/2015 ACT	Paper mill	Recovery Furnace - Non-Direct Contact with Dry -	Black Liquor Solids (BLS)	2.88	million lbs. of BLS	Nitrogen Oxides (NOx)		90	PPMDV	@8% O2	BACT-PSD	105.8	LB/H	3-HR. ROLLING	0		
AL-0302	ROCKTENN STEVENSON	ROCKTENN CP, LLC	AL	705-0014-X014	322130	04/29/2015 ACT	Pulp & Paper Mill	Recovery Boiler	Black Liquid	58334	LB/LB BL	Nitrogen Oxides (NOx)		120	PPM@8%O2	30 DAYS AVG	BACT-PSD	72.92	LB/H	3 HRS AVG	0		
AL-0320	GP BREWTON	GEORGIA-PACIFIC BREWTON LLC	AL	502-0001-X044	322130	01/03/2018 ACT		No. 4 Recovery Furnace	Black Liqour	1355	MMBtu/hr	Nitrogen Oxides (NOx)		90	PPMV @8% O2		BACT-PSD	221.9	LB/HR	3 HR	0		
AR-0156	GREEN BAY PACKAGING - ARKANSAS KRAFT DIVISION	GREEN BAY PACKAGING - ARKANSAS KRAFT DIVISION	AR	0224-AOP-R21	322130	02/08/2019 ACT	paperboard mill	Recovery Boiler	black liquor solids	401400	T/YR	Nitrogen Oxides (NOx)		80	LB/H		OTHER CASE-BY-CASE	313.1	T/YR		0		
*AR-0161	SUN BIO MATERIAL COMPANY	SUN BIO MATERIAL COMPANY	AR	2384-AOP-R0	322110	09/23/2019 ACT	A kraft paper mill designed with one high yield Kraft softwood Fiberline and two linerboard machiens. The plant is initially sized to support an approximate, nominal linerboard production capacity of 4,400 machine dry tons per day at varying base weights.	Recovery Boiler	Black Liquor Solids	2900	MMBtu/hr	Nitrogen Oxides (NOx)	Quaternary Air/Staged Combustion	85	PPMVD @ 8% O2	3 1-HOUR TESTS	BACT-PSD	0			0		
*AR-0161	SUN BIO MATERIAL COMPANY	SUN BIO MATERIAL COMPANY	AR	2384-AOP-R0	322110	09/23/2019 ACT	A kraft paper mill designed with one high yield Kraft softwood Fiberline and two linerboard machiens. The plant is initially sized to support an approximate, nominal linerboard production capacity of 4,400 machine dry tons per day at varying base weights.	Lime Kiln	Natural Gas	225	MMBtu/hr	Nitrogen Oxides (NOx)	Good Combustion Practices	180	PPMVD @ 10% O2	3 1-HOUR TESTS	BACT-PSD	0			0		
*AR-0161	SUN BIO MATERIAL COMPANY	SUN BIO MATERIAL COMPANY	AR	2384-AOP-R0	322110	09/23/2019 ACT	A kraft paper mill designed with one high yield Kraft softwood Fiberline and two linerboard machiens. The plant is initially sized to support an approximate, nominal linerboard production capacity of 4,400 machine dry tons per day at varying base weights.	Power Boiler	Biomass	1200	MMBtu/hr	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	0.06	LB/MMBTU	3-HOUR	BACT-PSD	0			0		

Boise White Paper LLC
Regional Haze "Effectively Controlled" Source Scenario Comparison Analysis
Attachment B: Hog Fuel Boiler NOx RBLC Search

Pollutant Name: NOx

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
AL-0250	BOISE WHITE PAPER	BOISE WHITE PAPER, LLC	AL	102-0001	322121	03/23/2010 ACT		COMBINATION BOILER	WOOD	435	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNERS	0.3	LB/MMBTU	3 H	BACT-PSD	130.5	LB/H	3 H	0		
*AR-0161	SUN BIO MATERIAL COMPANY	SUN BIO MATERIAL COMPANY	AR	2384-AOP-R0	322110	09/23/2019 ACT	A kraft paper mill designed with one high yield Kraft softwood Fiberline and two linerboard machiens. The plant is initially sized to support an approximate, nominal linerboard production capacity of 4,400 machine dry tons per day at varying base weights.	Power Boiler	Biomass	1200	MMBtu/hr	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	0.06	LB/MMBTU	3-HOUR	BACT-PSD	0			0		
CA-1203	SIERRA PACIFIC INDUSTRIES-LOYALTON	SIERRA PACIFIC INDUSTRIES	CA	SAC 87-01-A	221119	08/30/2010 ACT	20 MW COGENERATION POWER PLANT	RILEY SPREADER STOKER BOILER - Transient Period (see notes)	WOOD	335.7	MMBTU/H	Nitrogen Oxides (NOx)	SELECTIVE NON-CATALYTIC REDUCTION (SNCR)	102	PPM	@12% CO2, 8-HR ROLLING AVG	BACT-PSD	65	LB/H	8-HR ROLLING AVG	0		
CA-1203	SIERRA PACIFIC INDUSTRIES-LOYALTON	SIERRA PACIFIC INDUSTRIES	CA	SAC 87-01-A	221119	08/30/2010 ACT	20 MW COGENERATION POWER PLANT	RILEY SPREADER STOKER BOILER	WOOD	335.7	MMBTU/H	Nitrogen Oxides (NOx)	SELECTIVE NON-CATALYTIC REDUCTION (SNCR)	80	PPM	@12% CO2, 8-HR ROLLING AVG	BACT-PSD	50.75	LB/H	8-HR ROLLING AVG	0		
CA-1225	SIERRA PACIFIC INDUSTRIES-ANDERSON DIVISION	SIERRA PACIFIC INDUSTRIES	CA	SAC 12-01	321113	04/25/2014 ACT	31 MW COGENERATION AND LUMBER MANUFACTURING FACILITY	STOKER BOILER (NORMAL OPERATION)	BIOMASS	468	MMBTU/H	Nitrogen Oxides (NOx)	SNCR	0.13	LB/MMBTU	12-MONTH ROLLING BASIS	BACT-PSD	0.15	LB/MMBTU	3-HOUR BLOCK AVERAGE	0		
CA-1225	SIERRA PACIFIC INDUSTRIES-ANDERSON DIVISION	SIERRA PACIFIC INDUSTRIES	CA	SAC 12-01	321113	04/25/2014 ACT	31 MW COGENERATION AND LUMBER MANUFACTURING FACILITY	STOKER BOILER (STARTUP & SHUTDOWN PERIODS)	BIOMASS	468	MMBTU/H	Nitrogen Oxides (NOx)	SNCR	70.2	LB/H	8-HR AVG (STARTUP PERIODS)	BACT-PSD	70.2	LB/H	8-HR AVG (SHUTDOWN PERIODS)	0		
CT-0156	MONTVILLE POWER LLC	NRG ENERGY	CT	107-0056	221119	04/06/2010 ACT	43 MW STOKER FIRED BIOMASS; 82 MW TANGENTIALLY FIRED NATURAL GAS/ULS DISTILLATE UTILITY BOILER (7% ANNUAL CAPACITY FACTOR)	42 MW Biomass utility boiler	Clean wood	600	MMBTU/H	Nitrogen Oxides (NOx)	Regenerative SCR	0.06	LB/MMBTU	24 HR BLOCK	LAER	0			0		
CT-0162	PLAINFIELD RENEWABLE ENERGY, LLC	PLAINFIELD RENEWABLE ENERGY, LLC	CT	145-0049	221119	12/29/2010 ACT	37.5 MW Biomass Power Plant	Fluidized Bed Gasification	Wood	523.1	MMBtu/hr	Nitrogen Oxides (NOx)	SNCR	0.075	LB/MMBTU		LAER	45.3	PPMVD @7% O2	24 HR BLOCK	0		
GA-0141	WARREN COUNTY BIOMASS ENERGY FACILITY	OGETHORPE POWER CORPERATION	GA	4911-301-0016-P-01-0	221119	12/17/2010 ACT	The proposed project will include: a bubbling fluidized bed boiler with a maximum total heat input capacity of 1,399 MMBTU/H, 2 fire water pump emergency engines; a raw material handling & storage area; a sorbent storage silo; a boiler bed sand silo, a sand day	Boiler, Biomass Wood	Biomass wood	100	MW	Nitrogen Oxides (NOx)	Selective non-catalytic reduction system (SNCR)	0.1	LB/MMBTU	30 D ROLLING AV / CONDITION 2.9	BACT-PSD	648	TONS	12 MONTH ROLLING TOTAL / CONDITION 2.18	0		
*KS-0034	ABENGOA BIOENERGY BIOMASS OF KANSAS (ABBK)	ABENGOA BIOENERGY BIOMASS OF KANSAS (ABBK)	KS	C-11396	325193	05/27/2014 ACT	Abengoa Bioenergy Biomass of Kansas (ABBK) intends to install and operate a biomass-to-ethanol and biomass-to-energy production facility near Hugoton, Kansas.	biomass to energy cogeneration bioler	different types of biomass	500	MMBtu/hr	Nitrogen Oxides (NOx)	Selective Catalytic Reduction System (SCR) and an over-fire system (OFA)	0.3	LB/MMBTU	30-DAY ROLLING, INCLUDES SSM	BACT-PSD	157.5	LB/HR	1-HR AVE, INCLUDES SSM	0		
ME-0037	VERSO BUCKSPORT LLC	VERSO BUCKSPORT LLC	ME	A-22-77-4-A	322121	11/29/2010 ACT	Existing pulp (groundwood and thermomechanical) and paper making facility.	Biomass Boiler 8	Biomass	814	MMBTU/H	Nitrogen Oxides (NOx)	SNCR	0.15	LB/MMBTU	30 DAY ROLLING	BACT-PSD	244.2	LB/H		0		

Boise White Paper LLC
Regional Haze "Effectively Controlled" Source Scenario Comparison Analysis
Attachment C: Hog Fuel Boiler SO2 RBLC Search

Pollutant Name: SO2

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
*AR-0161	SUN BIO MATERIAL COMPANY	SUN BIO MATERIAL COMPANY	AR	2384-AOP-R0	322110	09/23/2019 ACT	A kraft paper mill designed with one high yield Kraft softwood Fiberline and two linerboard machiens. The plant is initially sized to support an approximate, nominal linerboard production capacity of 4,400 machine dry tons per day at varying base weights.	Power Boiler	Biomass	1200	MMBtu/hr	Sulfur Dioxide (SO2)	FGD/Dry Sorbent Injection	0.025	LB/MMBTU	3 1-HOUR TESTS	BACT-PSD	0			0		
CT-0156	MONTVILLE POWER LLC	NRG ENERGY	CT	107-0056	221119	04/06/2010 ACT	43 MW STOKER FIRED BIOMASS; 82 MW TANGENTIALLY FIRED NATURAL GAS/ULS DISTILLATE UTILITY BOILER (7% ANNUAL CAPACITY FACTOR)	42 MW Biomass utility boiler	Clean wood	600	MMBTU/H	Sulfur Oxides (SOx)	Low sulfur fuels	0.025	LB/MMBTU	3 HR BLOCK	BACT-PSD	0			0		
CT-0162	PLAINFIELD RENEWABLE ENERGY, LLC	PLAINFIELD RENEWABLE ENERGY, LLC	CT	145-0049	221119	12/29/2010 ACT	37.5 MW Biomass Power Plant	Fluidized Bed Gasification	Wood	523.1	MMBtu/hr	Sulfur Dioxide (SO2)	Spray Dryer, Bed Injection	0.035	LB/MMBTU		OTHER CASE-BY-CASE	15.4	PPMVD @7% O2	3 HR BLOCK	0		
GA-0141	WARREN COUNTY BIOMASS ENERGY FACILITY	OGETHORPE POWER CORPERATION	GA	4911-301-0016-P-01-0	221119	12/17/2010 ACT	The proposed project will include: a bubbling fluidized bed boiler with a maximum total heat input capacity of 1,399 MMBTU/H, 2 fire water pump emergency engines; a raw material handling & storage area; a sorbent storage silo; a boiler bed sand silo, a sand day	Boiler, Biomass Wood	Biomass wood	100	MW	Sulfur Oxides (SOx)	Dust sorbent injection system	0.01	LB/MMBTU	30 D ROLLING AV / CONDITION 2.12	BACT-PSD	56	TONS	12 MONTH ROLLING TOTAL / CONDITION 2.20	0		
*KS-0034	ABENGOA BIOENERGY BIOMASS OF KANSAS (ABBK)	ABENGOA BIOENERGY BIOMASS OF KANSAS (ABBK)	KS	C-11396	325193	05/27/2014 ACT	Abengoa Bioenergy Biomass of Kansas (ABBK) intends to install and operate a biomass-to-ethanol and biomass-to-energy production facility near Hugoton, Kansas.	biomass to energy cogeneration bioler	different types of biomass	500	MMBtu/hr	Sulfur Dioxide (SO2)	Injection of sorbent (lime) in combination with a dry flue gas desulfurization (FGD) system	0.21	LB/MMBTU	30-DAY ROLLING, INCLUDES SSM	BACT-PSD	110.25	LB/HR	MAX 1-HR, INCLUDES SS, EXCLUDES MALFUNCT	0		
LA-0249	RED RIVER MILL	INTERNATIONAL PAPER CO	LA	PSD-LA-562(M-4)	322130	05/09/2011 ACT	KRAFT PULP MILL WHICH PRODUCES UNBLEACHED LINERBOARD	NO. 2 HOGGED FUEL BOILER	HOGGED FUEL/BARK	992.43	MMBTU/H	Sulfur Dioxide (SO2)	USE OF LOW SULFUR FUELS	60	LB/H	HOURLY MAXIMUM	BACT-PSD	262.8	T/YR	ANNUAL MAXIMUM	0.06	LB/MMBTU	
ME-0037	VERSO BUCKSPORT LLC	VERSO BUCKSPORT LLC	ME	A-22-77-4-A	322121	11/29/2010 ACT	Existing pulp (groundwood and thermomechanical) and paper making facility.	Biomass Boiler 8	Biomass	814	MMBTU/H	Sulfur Dioxide (SO2)	0.7% sulfur when firing oil	0.8	LB/MMBTU	3-HR AVERAGE	BACT-PSD	651.2	LB/H		0		

Appendix A.2

Regional Haze Correspondence with Hassan Bouchareb

Dated May 29, 2020

-------- Original message --------
From: "Bouchareb, Hassan (MPCA)" <hassan.bouchareb@state.mn.us>
Date: 5/29/20 12:12 PM (GMT-06:00)
To: "Huziak, Kara" <KaraHuziak@BoisePaper.com>
Cc: "Rein, Patrick" <PatrickRein@boisepaper.com>
Subject: [EXTERNAL] RE: Regional Haze Request - NOx question

Ms. Huziak,

Thank you for providing this information. Based on this information and information included in your request, I agree that the recovery furnace and boiler #2 qualify as effectively controlled and Boise White Paper does not need to conduct a four factor analysis for those emission units as requested in the January 29, 2020 RFI letter. Please note that I may have additional questions for you regarding these units as I work on preparing Minnesota's regional haze SIP; potentially in describing the units and expected operations for various portions of the regional haze rules.

I have one request for you that would be helpful for me. Eventually, I will be working to post the collection of four-factor analyses and facility responses to the MPCA's external website to facilitate review by interested, external folks. Would you please include your request to withdraw the four factor analysis for the recovery furnace and boiler #2 with your response to the RFI letter for Boiler #1?

It would be helpful to have everything in one package so I can provide it to our publication/web support teams when we get to that point.

Please let me know if you have any questions.

Thank you!

Hassan M. Bouchareb | Engineer
Minnesota Pollution Control Agency (MPCA)
Office: (651) 757-2653 | Fax: (651) 296-8324
Pronouns: he/him/his
Hassan.Bouchareb@state.mn.us | www.pca.state.mn.us

From: Huziak, Kara <KaraHuziak@BoisePaper.com>
Sent: Thursday, May 21, 2020 3:45 PM
To: Bouchareb, Hassan (MPCA) <hassan.bouchareb@state.mn.us>
Subject: Regional Haze Request - NOx question

Mr. Bouchareb,

Thank you for the update. Regarding the history of the BACT analysis for the Recovery Furnace, we've prepared the following table which provides the history of the permitting for the Recovery Furnace with a focus on the NO_X emissions limit changes. It is important to note that the existing permit limit (*110* *lbs/hour using 30-day Rolling Average; This is equivalent to 80 ppm on a dry basis, corrected to 8% oxygen*) is the result of a BACT analysis. It is also important to note that the Recovery Furnace utilizes a two-stage tertiary air system (i.e., quaternary overfire air) which is the control system listed as BACT in the RBLC and in Sappi's 2017 major air permit amendment (Air Permit Number 01700002-101 – see the BACT analysis in Section 3.3.3 of the TSD).

Permit #	Issued Date	Description
001	09/1990	The NO_X permit limit in the first Title V permit was: • Nitrogen Oxides: less than or equal to 86.9 lbs/hour using 30-day Rolling Average. This is equivalent to 80 ppm on a dry basis, corrected to 8% oxygen. • Title I Condition: 40 CFR Section 52.21 (modeling and netting); Minn. R. 7007.3000
003	10/2000	This permit was for the Efficiency Improvement Project which was permitted under PSD. The TSD describes the NO_X limit as follows: • NO_X limit increased from 86.9 to 94.5 lbs/hour and identified as BACT limit; the previous limit was not a BACT limit. Although the NO_X limit on this emission unit has been increased, the NO_X emission cap for the facility has not been increased. The NO_X emission rate on a pound per ton of black liquor solids basis is the same as what it was previously, but since the black liquor production will be increasing, the lbs/hour emission rate will increase. The permit limit was listed as follows: • Nitrogen Oxides: less than or equal to 94.5 lbs/hour using 30-day Rolling Average. • Title I Condition: 40 CFR Section 52.21(j) (BACT limit); Minn. R. 7007.3000
006	11/2004	This permit amendment included an increase in the NO_X emission limit for the Recovery Furnace. The NO_X emission limit increase was based on an update to the NO_X BACT analysis because the existing permit limit was a BACT limit. The permit limit was listed as follows: • Nitrogen Oxides: less than or equal to 102 lbs/hour using 30-day Rolling Average. This is equivalent to 80 ppm on a dry basis, corrected to 8% oxygen. • Title I Condition: 40 CFR Section 52.21(j) (BACT limit); Minn. R. 7007.3000
009	10/2008	This permit amendment included increase to the Total Facility black liquor solids (BLS) production limit from 41,000 to 44,200 tons/month and the NO_X emission limit. The permit amendment also increased the NO_X emission limit which included an update to the NO_X BACT analysis because the existing permit limit was a BACT limit. As described in the TSD, "*the requested NOx and CO emission limits increase is necessary to maintain the mass emission limits (lb/hr) in proper proportion to the maximum permitted annual BLS rate*" (Air Permit 07100002-009 – see page 16 of the TSD). The permit limit was listed as follows: • Nitrogen Oxides: less than or equal to 110 lbs/hour using 30-day Rolling Average. This is equivalent to 80 ppm on a dry basis, corrected to 8% oxygen. • Title I Condition: 40 CFR Section 52.21(j) (BACT limit); Minn. R. 7007.3000
010	03/2009	This Major Amendment was requested by the facility to allow for the blending of distillate oil (#1 and #2) with the black liquor solids (BLS) to provide the facility with additional fuel flexibility for the Recovery Furnace (Emission Unit 320). However, there was no change to the NO_X emission limit.

014	06/2017	This permit action is the reissuance of the Part 70 operating permit. In addition to the reissuance, a major permit amendment was incorporated into the permit to increase the total facility BLS production limit from 44,200 to 46,410 tons per month using a 12-month rolling average. However, the facility did not request a change to the NO_X emission limit.
101	04/2020	This permit action is a Major Amendment for an increase in BLS throughput to 49,890 tons/month. However, the facility did not request a change to the NO_X emission limit.

Please let me know if you have questions or need additional assistance for your review.

Thank you,

Kara Huziak

Environmental, Air
400 2nd Street
International Falls, MN 56649

218.285.5449 Office
218.417.0624 Cell

From: Bouchareb, Hassan (MPCA) <hassan.bouchareb@state.mn.us>
Sent: Wednesday, May 20, 2020 2:12 PM
To: Huziak, Kara <KaraHuziak@BoisePaper.com>
Cc: Rein, Patrick <PatrickRein@boisepaper.com>
Subject: [EXTERNAL] RE: Regional Haze Request

Hello Kara,

Thanks for your patience so far! I'm currently reviewing your request and so far it looks like we'll likely be able to grant the request. One thing you could help me with is the history of the BACT analysis for the Recovery Furnace (i.e., when it was first completed, updates since then, etc.). I was looking through the previous permits for Boise and I noticed the lb/hr NO_X values have changed while the equivalent ppm concentration has remained the same. From my review so far, it looks like that is due to production/capacity increases that allowed the furnace to process more BLS but it would be helpful if you could provide the history of the changes to help clarify how the ppm value from the previous BACT analysis has remained while the hourly emission rates have increased.

Additionally, It's not clear to me if controls are implemented to allow Boise to meet these NO_X limits or if it is managed through other methods. I see that CEMS are used to demonstrate compliance with the limits, but if you could help clarify what, if any, controls are implemented for NO_X that would be helpful as well.

Let me know if you have any questions.

Thanks again!

Hassan M. Bouchareb | Engineer
Minnesota Pollution Control Agency (MPCA)
Office: (651) 757-2653 | Fax: (651) 296-8324
Pronouns: he/him/his
Hassan.Bouchareb@state.mn.us | www.pca.state.mn.us

From: Huziak, Kara <KaraHuziak@BoisePaper.com>
Sent: Wednesday, May 20, 2020 9:09 AM
To: Bouchareb, Hassan (MPCA) <hassan.bouchareb@state.mn.us>
Cc: Rein, Patrick <PatrickRein@boisepaper.com>
Subject: RE: Regional Haze Request

Hello Mr. Bouchareb,

I am writing to follow up on our recent 4-Factor analysis request. Do you have any questions or require clarification regarding the request? We are happy to meet with you by phone to discuss further.

Thank you,

Kara Huziak

Environmental, Air
400 2nd Street
International Falls, MN 56649

218.285.5449 Office
218.417.0624 Cell

From: Huziak, Kara
Sent: Tuesday, May 12, 2020 12:36 PM
To: Hassan.Bouchareb@State.mn.us
Cc: Rein, Patrick <PatrickRein@boisepaper.com>
Subject: Regional Haze Request

Mr. Bouchareb,

Please find attached a digital copy of a letter mailed to your attention requesting further consideration for EQUI 09 and EQUI 16 at the International Falls, MN (Air Permit 07100002-101, agency interest #443).

We look forward to discussing this request with you.

Thank you,

Kara Huziak

Environmental, Air
400 2nd Street
International Falls, MN 56649

218.285.5449 Office
218.417.0624 Cell

Appendix B

RACT/BACT/LAER Clearinghouse (RBLC) Review

Summary for Natural Gas Boilers for NO_X

Boise White Paper LLC
Appendix B: Natural Gas Boiler NOx RBLC Search

Pollutant Name: NOx

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
VA-0328	C4GT, LLC	NOVI ENERGY	VA	52588	221112	04/26/2018 ACT	Natural gas-fired combined cycle power plant	Auxiliary Boiler	Natural Gas	902	mmcf/y	Nitrogen Oxides (NOx)	Low NOx burners	0.011	LB/MMBTU	CORRECTED TO 3% O2	BACT-PSD	1.2	LB/H		0		
TN-0162	JOHNSONVILLE COGENERATION	TENNESSEE VALLEY AUTHORITY	TN	970816F	221112	04/19/2016 ACT	Existing gas-fired combustion turbine with new heat recovery steam generator (HRSG) with duct burner and two new gas-fired auxiliary boilers.	Two Natural Gas-Fired Auxiliary Boilers	Natural Gas	450	MMBtu/hr	Nitrogen Oxides (NOx)	Good combustion design and practices, selective catalytic reduction (SCR), low-NOX burners with flue gas recirculation	0.013	LB/MMBTU		BACT-PSD	0			0		
TX-0576	PIPE MANUFACTURING STEEL MINI MILL	TPCO AMERICA INC	TX	PSDTX1188 AND 86860	331513	04/19/2010 ACT	converts scrap steel into seamless pipe	vacuum degasser boiler	natural gas	40	MMBTU/H	Nitrogen Oxides (NOx)	good combustion practice	0.1	LB/MMBTU		BACT-PSD	0			0		
PA-0306	TENASKA PA PARTNERS/WESTMORELAND GEN FAC	TENASKA PA PARTNERS LLC	PA	65-00990 C/E	221112	02/12/2016 ACT	The plan approval will allow construction and temporary operation of a power plant is a single 2 on 1 combined cycle turbine configuration with 2 combustion turbines serving a single steam turbine generator equipped with heat recovery steam generator	245 MMBtu natural gas fired Auxiliary boiler	Natural Gas	1052	MMscf/yr	Nitrogen Oxides (NOx)	Good combustion practices and ULNOx burners	0.011	LB/MMBTU		LAER	9	PPMDV @ 15% O2		0		
LA-0314	INDORAMA LAKE CHARLES FACILITY	INDORAMA VENTURES OLEFINS, LLC	LA	PSD-LA-813	325199	08/03/2016 ACT	modify and restart-up a mothballed facility to produce 1,009 million lbs/yr of ethylene	boiler A and B (010 and 011)	natural gas/fuel gas	248	mm btu/hr (each)	Nitrogen Oxides (NOx)	good combustion practices; fueled by natural gas or process fuel gas; ULNB (FGR and economizer)	0.06	LB/MM BTU	THREE ONE-HOUR TEST AVERAGE	BACT-PSD	0			0		
LA-0314	INDORAMA LAKE CHARLES FACILITY	INDORAMA VENTURES OLEFINS, LLC	LA	PSD-LA-813	325199	08/03/2016 ACT	modify and restart-up a mothballed facility to produce 1,009 million lbs/yr of ethylene	boiler B-201	natural gas/fuel gas	229	mm btu	Nitrogen Oxides (NOx)	good combustion practices; fueled by natural gas or process fuel gas; ULNB (FGR and economizer)	0.06	LB/MM BTU	THREE ONE-HOUR TEST AVERAGE	BACT-PSD	0			0		
*TN-0164	TVA - JOHNSONVILLE COGENERATION	TENNESSEE VALLEY AUTHORITY	TN	972969	221112	02/01/2018 ACT	Combustion turbines and combined cycle plant	Two Auxiliary Boilers	Natural Gas	450	MMBtu/hr, each boiler	Nitrogen Oxides (NOx)	SCR, low-NOX burners, flue gas recirculation, good combustion design & practices	0.013	LB/MMBTU	30-DAY AVG EXCLUDING STARTUP & SHUTDOWN	BACT-PSD	0.2	LB/MMBTU	30-DAY AVG, APPLIES AT ALL TIMES	0		
OH-0354	KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	OH	P0108853	325212	01/15/2013 ACT	Thermoplastic elastomer manufacturing facility	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Nitrogen Oxides (NOx)	Low-NOx burners	0.12	LB/MMBTU	BURNING DISTILLATE OIL	N/A	392.83	T/YR		0.1	LB/MMBTU	BURNING NATURAL GAS
AK-0083	KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	AQ0083CPT06	325311	01/06/2015 ACT	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Nitrogen Oxides (NOx)	Ultra Low NOx Burners	0.01	LB/MMBTU	30-DAY AVERAGE	BACT-PSD	0			0		
AR-0121	EL DORADO CHEMICAL COMPANY	LSB INDUSTRIES, INC.	AR	0573-AOP-R16	325311	11/18/2013 ACT	CHEMICAL MANUFACTURING, INCLUDING NITRIC ACID PRODUCTION, SUFLURIC ACID PRODUCTION, AMMONIA PRODUCTION, AND AMMONIA NITRATE PRODUCTION	START-UP BOILER	NATURAL GAS	240	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNERS AND FLUE GAS RECIRCULATION	4.32	LB/H	ROLLING 3 HOUR AVERAGE	BACT-PSD	0.018	LB/MMBTU	ROLLING 3 HOUR AVERAGE	0		
IN-0263	MIDWEST FERTILIZER COMPANY LLC	MIDWEST FERTILIZER COMPANY LLC	IN	129-36943-00059	325311	03/23/2017 ACT	STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	NATURAL GAS AUXILIARY BOILERS (EU-012A, EU-012B,	NATURAL GAS	218.6	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNERS WITH FLUE GAS RECIRCULATION AND GOOD COMBUSTION PRACTICES	20.4	LB/MMCF EACH	3 HOUR AVERAGE	BACT-PSD	1877.39	MMCF/12 MONTH EACH	ROLLING AVERAGE	0		
IN-0179	OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	147-32322-00062	325311	09/25/2013 ACT	NITROGENOUS FERTILIZER PRODUCTION PLANT	FOUR (4) NATURAL GAS-FIRED BOILERS	NATURAL GAS	218	MMBTU/HR, EACH	Nitrogen Oxides (NOx)	ULTRA LOW NOX BURNERS FLUE GAS RECIRCULATION	20.4	LB/MMCF	24-HR AVERAGE	BACT-PSD	0			0		
LA-0272	AMMONIA PRODUCTION FACILITY	DYNO NOBEL LOUISIANA AMMONIA, LLC	LA	(225) 219-3417"	2873	10/08/2012 ACT	2780 TON PER DAY AMMONIA PRODUCTION FACILITY	COMMISSIONING BOILERS 1 & 2 (CB-1 & CB-2)	NATURAL GAS	217.5	MM BTU/HR	Nitrogen Oxides (NOx)	FLUE GAS RECIRCULATION, LOW NOX BURNERS, AND GOOD COMBUSTION PRACTICES (I.E., PROPER DESIGN OF BURNER AND FIREBOX COMPONENTS; MAINTAINING	11.92	LB/H	HOURLY MAXIMUM	BACT-PSD	21.86	T/YR	ANNUAL MAXIMUM	0.05	LB/MM BTU	ANNUAL AVERAGE
TX-0811	LINEAR ALPHA OLEFINS PLANT	INEOS OLIGOMERS USA LLC	TX	136130 AND N250	325110	11/03/2016 ACT	Manufactures linear alpha olefins (LAO) from ethylene	Industrial-Sized Furnaces, Natural Gas-fired	natural gas	217	MM BTU / H	Nitrogen Oxides (NOx)	Low-NOX burners and Selective Catalytic Reduction (SCR). Ammonia slip limited to 10 ppmv (corrected to 3% O2) on a 1-hr block average.	0.006	LB / MM BTU	HHV BASIS, ANNUAL AVERAGE	LAER	0.014	LB/MMBTU	HHV BASIS, 1-HR AVERAGE	0		
OH-0374	GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	P0122594	221112	10/23/2017 ACT	1,650 MW combined cycle combustion turbine electrical generating facility	Auxiliary Boiler (B001)	Natural gas	185	MMBTU/H	Nitrogen Oxides (NOx)	low-NOx burners and flue gas recirculation	3.7	LB/H		BACT-PSD	9.25	T/YR	PER ROLLING 12 MONTH PERIOD	0.02	LB/MMBTU	
VA-0325	GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	52525	221112	06/17/2016 ACT	The proposed project will be a new, nominal 1,600 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator	AUXILIARY BOILER (1) AND FUEL GAS HEATERS (6)	NATURAL GAS	185	MMBTU/HR	Nitrogen Oxides (NOx)	ultra low-NO$_x$ burners	0.011	LB/MMBTU		N/A	0			0		
MI-0427	FILER CITY STATION	FILER CITY STATION LIMITED PARTNERSHIP	MI	66-17	221112	11/17/2017 ACT	New natural gas combined heat and power plant proposed at existing cogenerating power plant permitted to burn wood, coal and tire derived fuel.	EUAUXBOILER (Auxiliary boiler)	Natural gas	182	MMBTU/H	Nitrogen Oxides (NOx)	LNB that incorporate internal (within the burner) FGR and good combustion practices.	0.04	LB/MMBTU	30 DAY ROLLING AVERAGE	BACT-PSD	0			0		
MI-0423	INDECK NILES, LLC	INDECK NILES, LLC	MI	75-16	221112	01/04/2017 ACT	Natural gas combined cycle power plant.	EUAUXBOILER (Auxiliary Boiler)	natural gas	182	MMBTU/H	Nitrogen Oxides (NOx)	Low NOx burners/Flue gas recirculation and good combustion practices.	0.04	LB/MMBTU	30 DAY ROLLING AVG TIME PERIOD	BACT-PSD	0			0		
TX-0641	PINECREST ENERGY CENTER	PINECREST ENERGY CENTER LLC	TX	PSDTX1298	221122	11/12/2013 ACT	Combinec Cycle Electric Generating Plant	Auxiliary boiler	natural gas	150	MMBTU/H	Nitrogen Oxides (NOx)	low NOx burners	16	PPMVD	INITIAL STACK TEST, 3% OXYGEN	BACT-PSD	0			0		
TX-0708	LA PALOMA ENERGY CENTER	LA PALOMA ENERGY CENTER, LLC	TX	101542 PSDTX1288	221112	02/07/2013 ACT	The proposed project is a new electric power plant, fueled by pipeline quality natural gas. The design of the plant is standard combined cycle (CC) technology.	boiler	natural gas	150	MMBTU/H	Nitrogen Oxides (NOx)	low-NOx burners, limited use	0.02	LB/MMBTU	3-HR ROLLING AVERAGE	BACT-PSD	0			0		
OH-0363	NTE OHIO, LLC		OH	P0116610	221112	11/05/2014 ACT	Combined-cycle, natural gas-fired power plant	Auxiliary Boiler (B001)	Natural gas	150	MMBTU/H	Nitrogen Oxides (NOx)	Ultra low NOx burner	1.65	LB/H		BACT-PSD	3.3	T/YR	PER ROLLING 12 MONTH PERIOD	0.011	LB/MMBTU	
TX-0712	TRINIDAD GENERATING FACILITY	SOUTHERN POWER COMPANY	TX	111393 PSDTX1368	221112	11/20/2014 ACT	Southern Power Company (SPC) is proposing to construct an electric generating facility near Trinidad, Henderson County, Texas. The Trinidad Generating Facility (TGF) will include a natural gas-fired combined cycle combustion turbine generator (CTG) equipped with	boiler	natural gas	110	MMBTU/H	Nitrogen Oxides (NOx)	ultra-low NOx burners, limited use	9	PPMVD	@15% O2	BACT-PSD	0			0		
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	MOUNDSVILLE POWER, LLC	WV	R14-0030	221112	11/21/2014 ACT	Nominal 549 mW(output) natural gas-fired combined cycle power plant.	Auxiliary Boiler	Natural Gas	100	mmBtu/hr	Nitrogen Oxides (NOx)	Ultra Low-NOx Burners, Flue-Gas Recirculation, & Good Combustion Practices	2	LB/H		BACT-PSD	0			0.02	LB/MMBTU	
TX-0731	CORPUS CHRISTI TERMINAL CONDENSATE SPLITTER	MAGELLAN PROCESSING LP	TX	118270 AND PSDTX1398	324110	04/10/2015 ACT	100 MBpd topping refinery	Industrial-Size Boilers/Furnaces	natural gas	0		Nitrogen Oxides (NOx)	Selective catalytic reduction (SCR)	0.006	LB/MMBTU	12-MONTH AVG	BACT-PSD	0.01	LB/MMBTU	BLOCK 1-HR AVG	0		
CA-1206	STOCKTON COGEN COMPANY	APMC STOCKTON COGEN	CA	SJ 85-04	221112	09/16/2011 ACT	49.9 MW COGENERATION POWER PLANT OWNED BY AIR PRODUCTS MANUFACTURING CORPORATION (APMC) STOCKTON COGEN AND LOCATED IN STOCKTON, CALIFORNIA	AUXILIARY BOILER	NATURAL GAS	178	MMBTU/H	Nitrogen Oxides (NOx)		7	PPMVD	@3% O2	BACT-PSD	0.0085	LB/MMBTU		0		
CA-1212	PALMDALE HYBRID POWER PROJECT	CITY OF PALMDALE	CA	SE 09-01	221112	10/18/2011 ACT	570 MW NATURAL GAS FIRED COMBINED CYCLE POWER PLANT WITH AN INTEGRATED 50 MW SOLAR THERMAL PLANT	AUXILIARY BOILER	NATURAL GAS	110	MMBTU/H	Nitrogen Oxides (NOx)		9	PPMVD	@3% O2, 3-HR AVG	BACT-PSD	0			0		
OH-0336	CAMPBELL SOUP COMPANY	CAMPBELL SOUP COMPANY	OH	P0106678	311422	12/14/2010 ACT	Canned food maufacturing facility.	Boilers (3)	Natural Gas	0		Nitrogen Oxides (NOx)		0.04	LB/MMBTU	BASED ON MFG. GUARANTEE	OTHER CASE-BY-CASE	63.08	T/YR	ROLLING 12 MO. FROM 3 BOILERS TOGETHER	0		

Appendix C.1

Boiler #1 Cost Calculations for NO_X Control (SCR)

Boise - International Falls, MN
#1 Boiler
NOX SCR Screening Calculations

	Boiler 1		Comment
Max Firing Rate	398	MMBtu/hr	PTE Calculations for Boiler 1.
NOX Emission Rate (Uncontrolled)	0.13	lb/MMBtu	2019 Air emission inventory (see "Data Inputs")
NOX Controls Emission Rate	0.04	lb/MMBtu	Target (see "Data Inputs")
System Capacity Factor (Actuall rate vs. max firing rate at 8760)	39.8%		Actual fuel per year / Maxium fuel per year (See "SCR Design Parameters")
Uncontrolled Emissions	90.9	ton/year	Calculated from Above
Emission Inventory Emissions	90.9	ton/year	From 2019 Emission Inventory For comparison only
Control Efficiency	69%		Based on target emission rate above (mid-point of pulp and paper in Table 1.2)
Controlled Emissions	27.8	ton/year	Calculated from Above
Total Capital Investment (TCI)	$7,828,245		From "Cost Estimate" worksheet
Total Annual Cost (TAC) =	$970,836	per year in 2020 dollars	From "Cost Estimate" worksheet
NOx Removed =	63.1	tons/year	From "Cost Estimate" worksheet
Cost Effectiveness =	$15,375	per ton of NOx removed in 2020 dollars	From "Cost Estimate" worksheet

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 398.0 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,020 Btu/scf

What is the estimated actual annual fuel consumption? 1,414,842,703 scf/Year

Enter the net plant heat input rate (NPHR) 8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 1129 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

○ Method 1
○ Method 2
● Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR}) 351 days

Number of days the boiler operates (t_{plant}) 351 days

Number of SCR reactor chambers (n_{scr}) 1

Number of catalyst layers (R_{layer}) 3

Inlet NO_x Emissions (NOx_{in}) to SCR	0.131	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.04	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	144512	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	20,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	330	^{o}F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	484	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used: Ammonia ▼

Enter the cost data for the proposed SCR:

Desired dollar-year	2020		
CEPCI for 2020	592.1	Enter the CEPCI value for 2020 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5	Percent*	* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0676	$/kWh	* $0.0676/kWh is a default value for electrity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) = 0.005
Administrative Charges Factor (ACF) = 0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	398	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	3,418,117,647	scf/Year	
Actual Annual fuel consumption (Mactual) =		1,414,842,703	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.398	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	3487	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	69.5	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	36.22	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	63.14	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.87		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	144,512	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	24.34	/hour	
Residence Time	1/V_{space}	0.04	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.04		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.1	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.4866	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	5,937.37	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	151	ft^2

Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	14	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	173	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	13.2	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	94	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	14	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	49	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	6	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	2,200	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	204.65	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$7,828,245	in 2020 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$312,615	in 2020 dollars
Indirect Annual Costs (IDAC) =	$658,221	in 2020 dollars
Total annual costs (TAC) = DAC + IDAC	$970,836	in 2020 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$39,141	in 2020 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$6,624	in 2020 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$48,239	in 2020 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$218,610	in 2020 dollars
Direct Annual Cost =		$312,615	in 2020 dollars

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,997	in 2020 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$655,224	in 2020 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$658,221	in 2020 dollars

Cost Effectiveness

Total Annual Cost (TAC) =	$970,836	per year in 2020 dollars
NOx Removed =	63	tons/year
Cost Effectiveness =	$15,374.88	per ton of NOx removed in 2020 dollars

Appendix C.2

Boiler #1 Cost Calculations for NO_X Control (LNB with FGR and OFA)

Low-NOx Burner (LNB) with Flue Gas Recirculation (FGR) and Overfire Air (OFA) Cost Estimate for Boise Paper LLC
Jun 23, 2020

As we talked on last Monday with a few assumptions, this is a high level estimate to support your order of magnitude request:

- General comments:
    - With your described emissions requirements we expect need of FGR to obtain the NOx limits. Unit operating data and a study/test could confirm this need.
    - Budget pricing is not an offer to sell.
    - Estimate is based on past work, future interface with sub vendors could be impacted by COVID 19 issues, or other business impacting conditions,
        - Examples, but not limited to (all of which could impact price and lead time)
            - price impacts (raw materials costs, labor rates…),
            - vendors out of business,
            - transportation disruptions,
            - manufacturing disruptions.
    - Asbestos mitigation is not considered in estimate and could be considerable if abatement is necessary.
    - Lead paint abatement is also not considered in estimate and also could be significant impact to cost.
    - Past installations were reviewed to accommodate best installation designs. With description of site and no drawings, budget price could be impacted due to unknown routing/obstructions.
    - No modifications are considered to radiant or convective heating surface or temperature control of final steam conditions.

- Scope boundaries would be:
    - Gas at inlet/outlet to main gas skid (not sure of your gas piping into the mill or capacity)
    - Gas at inlet/outlet to individual burners gas skids
    - Electrical at fan (no supply of electrical- BUS/Breakers wiring to fan, etc.)
    - Controls (no hardware/software for control system). Subs to supply logic for combustion control, and burner management
    - Existing windbox with modifications; repairs to existing windbox are not considered (physical conditions need to be evaluated)
    - FGR fan – conceptual ducting (this is a wildcard based on unfamiliar – described difficult routing)
- Base scope would typically include:
    - Engineering
    - T – fired burner gas/air buckets/lighters scope
    - Overfire air scope (assume FGR/COFA due to short furnace)
    - Gas skids
        - Main gas header valve train
        - Header vent spool
        - Burner gas valve train (one per burner)
        - Main flame scanners
    - FGR fan
    - FGR flue/dampers

- Other scope not supplied includes:
    - Field Service.
        - Installation, demolition, field testing, or construction management of the proposed equipment.
        - Load analysis of existing structural steel or any required re-enforcement
        - Engineering, Material, or Installation of any required modifications to existing structural support steel to accommodate new burner access platform addition if required, fan platform, valve rack supports or piping supports.
        - Modifications to the Combustion control system (DCS) software, configuration, review of existing loop diagrams, etc.
        - Modifications to the Combustion control system (DCS) equipment such as IO cards or other hardware necessary for the system to accept the new proposed burner and ignitor equipment.
        - Wiring design or material supply including site specific wiring diagrams, loop sheets, interconnection drawings, raceway layout drawings, wire, conduit, or cable trays.
        - Permits, licenses, and other Governmental Agency permission required to construct and operate the proposed equipment.
        - Spare or replacement parts.
        - Federal, state, or local sales and use taxes.
        - Baseline or Acceptance testing.
        - Damper control logic changes (if required).
        - Fees associated with any onsite approval agencies.
        - Boise Inc. to provide natural gas regulated to approximately 100 to 150 psig to the gas header inlet, with a maximum design pressure of 200 psig.
        - Fuel/Air piping beyond supplied valve racks (piping supply to main header valve rack, piping between valve racks or to/from burners and local valve racks).
        - Vent piping from valve racks to atmosphere.
        - Training Manual & Training.
        - Existing Primary Outlet header (temperature monitoring recommended).
        - Modifications to FD or ID fans.
        - Windbox interior compartment plates, windbox modifications or any repair or refurbishment which will be by others.
- Installation is based on a high level factor estimate and is subject to the above factors.

Pricing:

- Material $3.5M (see above)
- Installation $5M
    - General mechanical
    - Electrical
    - Piping
    - Controls (swag – based on no information available to understand existing)

Schedule:

Based on historic information a typical project span from receipt of order to delivery of equipment could be roughly 40-50 weeks. Thus added time for purchasing process along with staging materials and installation could add approximately 20 -30 weeks.

Other developmental cost typically provided by an Architectural Engineering firm and/or others are not included and could be required to support balance of plant aspects of this project. This could include but is not limited to:

- Controls integration of new equipment (factors of available space in existing electrical system and I/O points in control system for example)
- Stack monitoring equipment or data management systems for new emission reporting
- Structural aspect of new equipment integrated into the existing steel.
- Instrument air requirements as taxed to existing systems
- Existing equipment conditions (integration of new systems into old equipment can require significant investment to improve conditions of existing equipment to support intended integration of the new systems if existing is damaged or modified).

Boise - International Falls, MN
#1 Boiler
Table 1: LNB-FGR Summary

	Boiler 1		Comment
Max Firing Rate	398	MMBtu/hr	PTE Calculations for Boiler 1
NO_X Emission Rate (Uncontrolled)	0.131	lb/MMBtu	2019 Air emission inventory (see Table 2)
NO_X Controls Emission Rate	0.050	lb/MMBtu	Target
Utilization Rate	41.4%		2019 Air emission inventory (see Table 2)
Uncontrolled Emissions	90.9	ton/year	Calculated from Above
Control Efficiency	62%		Calculated from Above
Controlled Emissions	34.7	ton/year	Calculated from Above
Total Capital Investment (TCI)	$11,144,531		From Table 3 - NOx Control - LNB with FGR
Total Annual Cost (TAC) =	$1,557,544	per year in 2020 dollars	From Table 3 - NOx Control - LNB with FGR
NOx Removed =	56.2	tons/year	Calculated from Above
Cost Effectiveness =	$27,707	per ton of NOx removed in 2020 dollars	Calculated from Above

Boise White Paper LLC
International Falls, MN
Table 2: Summary of Utility, Chemical, and Supply Costs

Operating Unit:	Boiler 1	**Study Year**	2020	Boise International Falls Site Specific Data
Emission Unit Number	EQUI17			EPA Default Scaled Value or Other Public Source
Stack/Vent Number	STRU25			Other Barr Project (public or not client specific)

	2020					
Item	**Unit Cost**	**Units**	**Cost**	**Year**	**Data Source**	**Notes**
Operating Labor	67.53	$/hr	60	2016	EPA SCR Cost Manual Spreadsheet	
Maintenance Labor	67.53	$/hr				Assumed to be equivalent to operating labor
Installation Labor	67.53	$/hr				Assumed to be equivalent to operating labor
Electricity	0.08	$/kwh			2015-2019 EIA Average prices for the commerical sector	
Natural Gas	3.90	$/kscf			2015-2019 EIA Average prices for the commerical sector	
Water	0.42	$/mgal	0.20	1995	Hbbing Taconite BART 2006 Study	
Cooling Water	0.42	$/mgal	0.23	1999	Hbbing Taconite BART 2006 Study	
Compressed Air	0.48	$/kscf	0.38	2012	Taconite FIP Docket - Control cost estimate for UTAC	
Chemicals & Supplies						
Lime	183.68	$/ton	145.00	2012	Taconite FIP Docket - Control cost estimate for UTAC	
Trona	285.00	$/ton			Reagent cost for trona from another Barr Engineering Co. Project.	
Urea 50% Solution	1.81	$/gallon	1.66	2017	EPA SCR Cost Manual Spreadsheet	
Estimated operating life of the catalyst ($H_{catalyst}$)	20,000	hours			EPA Control Cost Manual for SCR suggests 16,000 - 24,000 hours	
SCR Catalyst cost ($CC_{replace}$)	255	$/cubic foot	227	2016	EPA SCR Cost Manual Spreadsheet	Cost includes removal and disposal/regeneration of existing catalyst and installation of new catalyst
Fabric Filter Bags	228.02	$/bag	180	2012	Taconite FIP Docket - Control cost estimate for UTAC	
Other						
Sales Tax	6.875%			2020	Tax Foundation Sales Tax as of 1/1/2019	Minnesota specific sales tax, not including local tax
Interest Rate	5.50%			2016	EPA SCR Cost Manual Spreadsheet	
Solid Waste Disposal	63.34	$/ton	50	2012	Taconite FIP Docket - Control cost estimate for UTAC	
Contingencies	10%	of purchased equip cost (B)			EPA Cost Control Cost Manual Chapter 2	Suggested contingency range of 5% to 15% of total capital investment
Markup on capital investment (retrofit factor)	25%				EPA Cost Control Cost Manual Chapter 2	Use retrofit factor of 25% (add 25% to installation cost to account for items not Covered by vendor cost estimate such as (1) Structural aspect of new equipment integrated into the existing steel. and (2) Existing equipment conditions (integration of new systems into old equipment can require significant investment to improve conditions of existing equipment to support intended integration of the new systems if existing is damaged or modified).)
Operating Information						
Annual Op. Hrs	8,424	Hours			2019 Operating Data	
Utilization Rate	41.4%				Assumed	
Design Capacity	398.0	MMBTU/hr			PTE Calculations for Boiler 9	
Equipment Life	20	yrs			Assumed	
Temperature	370	Deg F			SMBSC CEMs Stack Temperature Data	2018-2020 Average, excluding periods of boiler shutdown/startup
Moisture Content	11.8%				2014 Boiler 1 Hg Stack Test Data	
Actual Flow Rate	209,000	acfm			2014 Boiler 1 Hg Stack Test Data	
Standardized Flow Rate	132,954	scfm @ 68º F	123,889	scfm @ 32º F	Calculated Value	
Dry Std Flow Rate	117,332	dscfm @ 68º F			Calculated Value	
Fuel higher heating value (HHV)	1,020	btu/scf			Standard value	
Plant Elevation	1,100	Feet above sea level				International Falls, MN elevation
# days boiler operates	351	days			2019 AEI	
	Baseline Emissions					
Pollutant	**Lb/Hr**	**Ton/Year**			**Unit: lb/mmbtu**	
Nitrous Oxides (NOx)	21.6	90.9			0.131	2019 CEMS lb/MMBtu average. Use "utlization rate" to adjust to match ton/year from emission inventory

Boise White Paper LLC
International Falls, MN
Table 3 NO$_x$ Control - Low NOx Burners (LNB) with Flue Gas Recirculation (FGR)

Operating Unit: **Boiler 1**

Emission Unit Number	EQUI17		Stack/Vent Number	STRU25	
Desgin Capacity	398	MMBtu/hr	Standardized Flow Rate	123,889	scfm @ 32º F
Expected Utiliztion Rate	41%		Temperature	370	Deg F
Expected Annual Hours of Operation	8,424	Hours	Moisture Content	11.8%	
Annual Interest Rate	5.5%		Actual Flow Rate	209,000	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	132,954	scfm @ 68º F
			Dry Std Flow Rate	117,332	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)		Vendor provided cost estimate						**3,500,000.00**
Purchased Equipment Total (B)	11.9%	increase to control device cost (A) to include MN Sales Tax and Freight						**3,915,625.00**
Installation - Standard Costs		Vendor provided cost estimate						5,000,000.00
Installation - Site Specific Costs								0.00
Installation Total								5,000,000.00
Total Direct Capital Cost, DC								8,915,625.00
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)						0.00
Total Capital Investment (TCI) with retrofit factor = (DC + IC) * (1 + retrofit factor)	25%	retrofit factor to account for issues not addressed by vendor such as structural steel, condition of existing equipment, asbestos, etc.						**11,144,531.25**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						111,997.69
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						1,445,546.77
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**1,557,544.47**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Cont. Emis. lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrous Oxides (NOx)	90.9	19.9	**0.05**	34.7	56.2	27,707

Notes & Assumptions

1 Total installed capital cost estimate from vendor

2 Assumed 0.5 hr/shift operatior and maintenance labor for LNB
3 Controlled emission factor based on vendor estimated burner/OFA performance
4 Installation costs do not account for the following:
 Controls integration of new equipment (factors of available space in existing electrical system and I/O points in control system for example)
 Stack monitoring equipment or data management systems for new emission reporting
 Instrument air requirements as taxed to existing systems
 Permits, licenses, and other Governmental Agency permission required to construct and operate the proposed equipment.

Boise White Paper LLC
International Falls, MN
Table 3 NOx Control - Low NOx Burners (LNB) with Flue Gas Recirculation (FGR)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)		Vendor provided cost estimate	**$3,500,000.00**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation		Costs included in vendor provided estimate	$0.00
MN Sales Taxes	6.9%	of control device cost (A)	$240,625.00
Freight	5%	of control device cost (A)	$175,000.00
Purchased Equipment Total (B)	12%		**$3,915,625.00**
Installation [1]			
Foundations & supports			$0.00
Handling & erection			$0.00
Electrical			$0.00
Piping			$0.00
Insulation			$0.00
Painting			$0.00
Installation Total		Vendor provided cost estimate	**$5,000,000.00**
Installation Total			**$5,000,000.00**
Total Direct Capital Cost, DC			**$8,915,625.00**
Indirect Capital Costs			
Engineering, supervision	0%	Costs included in vendor provided estimate	$0.00
Construction & field expenses	0%	Costs included in vendor provided estimate	$0.00
Contractor fees	0%	Costs included in vendor provided estimate	$0.00
Start-up	0%	Costs included in vendor provided estimate	$0.00
Performance test	0%	Costs included in vendor provided estimate	$0.00
Model Studies	0%	Costs included in vendor provided estimate	$0.00
Contingencies	0%	Costs included in vendor provided estimate	$0.00
Total Indirect Capital Costs, IC	0%	of purchased equip cost (B)	**$0.00**
Total Capital Investment (TCI) = DC + IC			**$8,915,625.00**
Site Preparation, as required		Site Specific (see retrofit factor)	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific (see retrofit factor)	
Total Site Specific Costs			**$0.00**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**$8,915,625.00**
Total Capital Investment (TCI) with Retrofit Factor	25%	retrofit factor to account for issues not addressed by vendor such as structural steel, condition of existing equipment, asbestos, etc.	**$11,144,531.25**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	67.53	$/Hr, 0.5 hr/8 hr shift, 8424 hr/yr	$35,554.82
Supervisor	15%	15% of Operator Costs	$5,333.22
Maintenance (2)			
Maintenance Labor	67.53	$/Hr, 0.5 hr/8 hr shift, 8424 hr/yr	$35,554.82
Maintenance Materials	100%	of maintenance labor costs	$35,554.82
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
Total Annual Direct Operating Costs			**$111,997.69**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	$67,198.62
Administration (2% total capital costs)	2%	of total capital costs (TCI)	$222,890.63
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	$111,445.31
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	$111,445.31
Capital Recovery	8%	for a 20- year equipment life and a 5.5% interest rate	$932,566.91
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**$1,445,546.77**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**$1,557,544.47**

Boise White Paper LLC
International Falls, MN
Table 3 NOx Control - Low NOx Burners (LNB) with Flue Gas Recirculation (FGR)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:
N/A

Replacement Parts & Equipment:
N/A

Electrical Use

Reagent Use & Other Operating Costs

Operating Cost Calculations	**Annual hours of operation:**	**8,424**
	Utilization Rate:	**41%**

Appendix D

May 20, 2021 Response to comments

PACKAGING CORPORATION OF AMERICA

May 20, 2021

Hassan M. Bouchareb
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155-4194

Re: Regional Haze Rule State Implementation Plan – Four-Factor Analysis Report Appendix D – Response to Comments

Dear Mr. Bouchareb:

On July 15, 2020, Boise White Paper, L.L.C. (Boise) submitted a Regional Haze Four-Factor Analysis (FFA) report in response to your request for information letter dated January 29, 2020. The FFA report will be used by MPCA to inform decisions for the Regional Haze State Implementation Plan (SIP) regarding what emission reductions are necessary to make reasonable progress. This letter is in response to your March 17, 2021 email which requested clarification regarding specific information that was included in the FFA report.

This letter provides additional or supporting information for each question in your March 17th "request summary" which was based on specific comments that you received from the Minnesota Pollution Control Agency (MPCA) technical reviewer, the U.S. Environmental Protection Agency (EPA) and the Federal Land Managers (FLMs).

Note that we are providing an updated copy of the FFA report to correct Appendix C.1 (Boiler #1 Cost Calculations for NO_X Control Measures (SCR)) and to attach this letter as Appendix D. No other changes have been made to the FFA report.

When reviewing the information below, it is important to note that Boise's FFA report presented control costs for Boiler #1 for selective catalytic reduction (SCR) (Appendix C.1) and low-NO_X burners (LNB) with flue gas recirculation (FGR) and overfire air (OFA) (Appendix C.2).

1.a. Address the potential typo regarding SCR vs. SNCR

The FFA for Boiler #1 was presented in Section 3 of the FFA report. Section 3.1 presented an evaluation of emission control technologies that should be evaluated based on the following methodology:

1. Search the RACT/BACT/LAER Clearinghouse (RBLC) for available control technologies with the following search criteria:
    - Similar emission unit type (process name)

- Similar fuel
- 10-year look back

2. Eliminate technologies that would not would not apply to the specific emission unit under consideration
3. Advance the remaining technologies for consideration in the four-factor analysis

Based on this information, the conclusion to Section 3.1 is that the technologies for consideration in the four-factor analysis are:

- SCR
- LNB/ULNB with or without FGR

Thus, SNCR was not further considered in the FFA report. However, when the final report was assembled in PDF format in July 2020, the preliminary control cost calculations that were conducted for SNCR were inadvertently inserted as appendix C.1 rather than the control cost calculations for SCR. However, the SCR control cost calculations were provided in August 2020 when MPCA requested the calculations in editable format.

To address this issue, Boise is providing an updated copy of the FFA report with the appropriate Appendix C.1 (Boiler #1 Cost Calculations for NO_X Control Measures (SCR)). As stated above, we have also inserted this letter as Appendix D to the FFA report. Note that no other changes were required within the document as SNCR was not a technology that was considered for Boiler #1.

1.b. …use the current prime interest rate (3.25%) or …provide supporting documentation to support the 5.5% interest rate…

EPA's control cost manual states a preference for firm-specific borrowing rates, but Boise is unable to provide that information as it is considered confidential business information. EPA's control cost manual also states that "*…if firm-specific nominal interest rates are not available, then the bank prime rate can be an appropriate estimate for interest rates.*"[1]

As shown in Figure 1, the bank prime rate can frequently change and the current rate of 3.25% is a historic low value. For example, the bank prime rate was at 5.5% as recently as July 2019 and was at 4.75% in February 2020 before dropping to the current 3.25% in April 2020. Although 3.25% may be available today, there is no certainty that this rate would be available at a future date.

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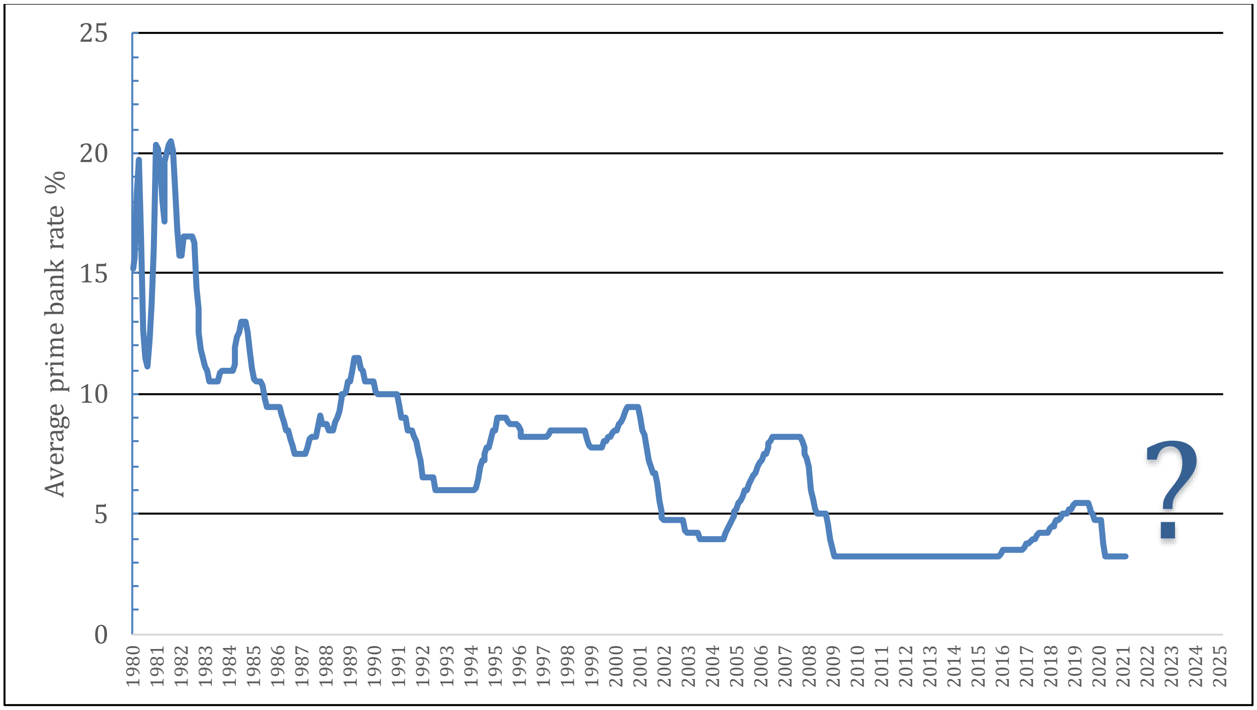
[1] EPA, Control Cost Manual, 7th Edition, Page 15.

Thus, Boise has used a 5.5% interest rate in the control cost calculations which is justified based on the historic and recent volatility in the bank prime rate and the uncertainty that would occur before financing a potential emission reduction project for startup by 2028.[2]

Figure 1: Bank Prime Rate 1980-Present



1.c. Provide additional information regarding the choices for expected equipment lifetime…

For SCR, Boise used an expected equipment lifetime of 20 years consistent with guidance in EPA's Control Cost Manual.[3] For the LNB with FGR and OFA, Boise used an expected lifetime of 20 years consistent with the guidance provided by the vendor who provided the cost estimate.

1.d. Provide copies of the vendor quotes…

The SCR control cost calculations (Appendix C.1) were develop using EPA's "Air Pollution Control Cost Estimation Spreadsheet for Selective Catalytic Reduction (SCR)" and, therefore, a vendor estimate was not used or required. The LNB with FGR and OFA control cost calculations were developed based on a vendor cost estimate as provided on the first 3 pages of Appendix C.2.

---

[2] MPCA has stated that emission reduction projects identified in the 2021 SIP update must be installed prior to the next SIP update in 2028.

[3] EPA, Control Cost Manual, 6th Edition, Page 2-48.

1.d. Provide copies of the… site preparation estimates…

The SCR control cost calculations (Appendix C.1) were develop using EPA's "Air Pollution Control Cost Estimation Spreadsheet for Selective Catalytic Reduction (SCR)" and, therefore, site preparation estimates were not used or required. The LNB with FGR and OFA control cost calculations (Appendix C.2) included site preparation estimates as part of the "retrofit factor" methodology. Additional information is provided in response to question 3.

2. …provide additional information on how the analysis for the recovery furnace… are sufficiently similar to the BACT analyses

As described in Appendix A.1 of the FFA report, Boise reviewed the RACT/BACT/LAER Clearinghouse (RBLC) for recovery furnace NO_X emission controls. Staged air combustion was the only emission control technology listed for combustion of black liquor solids – this is the same emission control technology utilized at Boise and, therefore, Boise already operates the only control technology that is listed in the RBLC. Furthermore, Boise's NO_X emission limit[4] (110 pound per hour 30-day rolling average, which is equivalent to 80 parts per million by volume, dry (ppmvd) adjusted to 8% oxygen) is more stringent than the RBLC sources which showed limits between 90 to 120 ppmvd adjusted to 8% oxygen.

Thus, the NO_X emission controls on the recovery furnace are equivalent to the recent BACT determinations because the recover furnace utilizes the only emission control technology listed in the RBLC and the emission limit is more stringent than those listed in the RBLC. Thus, there is a low likelihood that further emission reductions would be considered reasonable. Therefore, the source has effective controls technology in place and a four-factor analysis for this source is not necessary.[5]

2. …provide additional information on how the analysis for… boiler 2 are sufficiently similar to the BACT analyses

Boise previously conducted a NO_X BACT analysis for Boiler #2 for the installation of an overfire air project. MPCA's technical support document for this permit stated that "*SCR and SNCR control methods were determined to be technologically infeasible, due to the difficulties in obtaining the correct temperature window for injection, the problems of ammonia slip, the possibility of the creation of secondary salts within the system.*"[6] No changes have been made to Boiler #2 to change that conclusion. The BACT analysis concluded that "*…good combustion control was determined to be BACT for Boiler No. 2. In addition, the overfire project is itself a technology designed to minimize NO_X emissions.*" Thus, the main goal of evaluating the RBLC sources was to determine if the sources are substantially similar to Boiler #2 and, therefore, an updated BACT analysis could result in a different conclusion.

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[4] Air Permit 07100002-101, Condition 5.11.7.

[5] EPA, USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, Page 22.

[6] MPCA, Technical Support Document for Permit 07100002-001, 9/9/1999, Page 5.

As described in Appendix A.1 of the FFA report, Boise reviewed the RBLC for biomass boiler NO_X emission controls. The sources listed in Appendix A.1 that were required to install add-on controls (either SNCR or SCR) differ from Boiler #2. For example, Boiler #2 is a stoker-grate boiler while two sources were bubbling fluidized bed (*AR-0161 GA-0141), one source utilized fluidized bed gasification (CT-0162), and another said the source "will be fitted with a multi-level fuel feed system including biomass suspension firing which is substantively unique" (ME-0037). Furthermore, another source burned substantially different biomass (corn stove, wheat straw…) and did not burn wood biomass (*KS-0034). The RBLC also contained a 2014 permit for a new "state-of-the-art" boiler which could be designed to accommodate add-on controls (CA-1225) which would be fundamentally different design than Boiler #2 which was started up in 1965 with coal as a primary fuel source. These sources are not comparable to Boiler #2 due to these fundamental differences in design and, therefore the feasibility of operating the controls at these sources does not imply that the same controls could be operated successfully on Boiler #2.

Finally, there was a source that utilized SNCR but struggled to meet its concentration-based limit. The RBLC entry is from 2010 when they submitted an application to modify their BACT limit. The application stated that "*…significant quantities of ammonia are injected in order to achieve the necessary NO_X emission reductions to meet the current concentration limit (80 ppmvd @ 12 percent CO_2), occasionally resulting in the formation of a visible secondary plume*" (CA-1203). This source shutdown permanently shortly after this permit was issued. This source is an example of an unsuccessful SNCR installation, likely because the boiler did not have the correct temperature window for injection of the reagent.

The only boiler without add-on controls (AL-0250) has a limit of 0.3 lb/MMBtu which is less stringent than Boiler #2's NO_X emission limit[7] (100.2 lb/hr, which is equivalent to 0.25 lb/MMBtu at the maximum firing rate).

Thus, the NO_X emission controls on Boiler #2 are equivalent to the recent BACT determinations because the sources that have installed additional controls are fundamentally different in design and the existing emission limit is more stringent than comparable sources listed in the RBLC. This aligns with the previous determination that "*SCR and SNCR control methods were determined to be technologically infeasible, due to the difficulties in obtaining the correct temperature window for injection, the problems of ammonia slip, the possibility of the creation of secondary salts within the system.*"[8] Thus, there is a low likelihood that further emission reductions would be considered reasonable. Therefore, the source has effective controls technology in place and a four-factor analysis for this source is not necessary.[9]

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[7] Air Permit 07100002-101, Condition 5.15.7

[8] MPCA, Technical Support Document for Permit 07100002-001, 9/9/1999, Page 5.

[9] EPA, USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, Page 22.

3. Provide additional information regarding the selection of the chosen retrofit factor...

The SCR control cost calculations (Appendix C.1) used a retrofit factor of 1 (=0%) which implies that no substantial retrofit costs were accounted for in the cost estimate as a conservative approach. Because the control cost estimate was substantially higher than what would be considered cost effective, the retrofit factor was not further investigated for this technology. The LNB with FGR and OFA control cost calculations (Appendix C.2) used a retrofit factor of 1.25 (=25%) to estimate the items not included in the vendor quote such as structural steel, condition of existing equipment, asbestos, etc. (see page 2 of the vendor quote in Appendix C.2). The list is extensive, and it may be conservatively an underestimate.

Please let us know if you need any additional information or would like to discuss this submittal in more detail.

Sincerely,

Mike Wagner

Mike Wagner
Mill Manager

Attachment: Updated Four-Factor Analysis Report

MINNESOTA POLLUTION
CONTROL AGENCY

520 Lafayette Road North | St. Paul, Minnesota 55155-4194 | 651-296-6300
800-657-3864 | Use your preferred relay service | info.pca@state.mn.us | Equal Opportunity Employer

February 14, 2020

Peter Karakash, Environmental Health and Safety Administrator
Hibbing Public Utilities Commission
1902 6th Avenue East
Hibbing, MN 55746

RE: Request for Information - Regional Haze Rule, Reasonable Progress, Four Factor Analysis

Dear Mr. Karakash:

The Minnesota Pollution Control Agency (MPCA) is currently preparing information for the second planning period (Round 2) comprehensive update to Minnesota's Regional Haze State Implementation Plan (SIP) as required by the Regional Haze Rule (40 CFR § 51.308). States are responsible for developing a Regional Haze SIP that addresses regional haze in each Class I area located within the state and in each Class I area located outside the state which may be affected by emissions from sources within the state. The Regional Haze SIP is required to identify existing facilities that cause or contribute to visibility impairment; analyze, identify, and apply federally-enforceable control strategies for those sources; and periodically demonstrate reasonable progress toward reaching visibility goals. States are also responsible for periodic comprehensive updates to their Regional Haze SIP that address these same topics. Minnesota's Round 2 Regional Haze SIP must be submitted to the U.S. Environmental Protection Agency (U.S. EPA) by July 31, 2021.

Minnesota has two Class I areas within its borders, the Boundary Waters Canoe Area Wilderness (BWCA) and Voyageurs National Park (Voyageurs). Other nearby Class I areas include Isle Royale National Park in Michigan. Therefore, Minnesota must prepare a Regional Haze SIP that identifies sources that cause or contribute to visibility impairment in these areas. To meet the core requirements for regional haze for these areas, Minnesota must submit a SIP that contains the plan elements and supporting documentation for all required analyses identified in 40 CFR § 51.308(f).

In the first planning period (Round 1), the focus of the Regional Haze Rule was on establishing Best Available Retrofit Technology (BART) for certain older sources and reasonable progress towards national visibility goals. In Round 2, there are no BART requirements; therefore, the focus is on making reasonable progress. The U.S. Environmental Protection agency has defined the methodology that states must use to determine what measures are necessary to make reasonable progress in 40 CFR § 51.308(f)(2). At minimum, the reasonable progress analysis must use the four factors identified in 40 CFR § 51.308(f)(2)(i) to evaluate and determine the emission reduction measures necessary to make reasonable progress. The four factors are:

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

Data from the IMPROVE monitoring sites at BWCA and Voyageurs indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X).

You are receiving this letter because your facility was identified as a significant source of NO_X and SO_2 and is located close enough to the BWCA or Voyageurs to potentially cause or contribute to visibility impairment in these Class I areas. Therefore, the MPCA requests that you prepare a "Four Factor Analysis" for the following emission units:

1. Boiler No. 1A (EQUI 1 / EU 001) that addresses emissions of NO_X and SO_2
2. Boiler No. 3A (EQUI 3 / EU 003) that addresses emissions of NO_X and SO_2
3. Wood Fired Boiler (EQUI 7 / EU 007) that addresses emissions of NO_X

The analysis should be prepared using the U.S. Environmental Protection Agency guidance[1] that provides recommendations for how each of the factors should be determined.

Preparation of the comprehensive update to Minnesota's Regional Haze SIP will require extensive planning and review of sources in Minnesota. The MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to prepare the Regional Haze SIP. The MPCA expects air quality modeling of potential regional emissions reductions will be conducted beginning in spring 2020. I appreciate your attention to this matter and request that you **submit the Four Factor Analysis by July 31, 2020**.

If you have any questions regarding this matter, or would like to request a meeting to further discuss the contents of this letter, please contact me by phone at 651-757-2653 or by email at Hassan.Bouchareb@state.mn.us.

Sincerely,

Hassan Bouchareb

This document has been electronically signed.

Hassan M. Bouchareb
Engineer
Environmental Analysis and Outcomes Division

Cc: Deepa de Alwis, MPCA
Cory Boeck, MPCA
Frank Kohlasch, MPCA
Agency Interest ID 1145

Address questions and submittals requested above to:

Hassan M. Bouchareb
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155-4194
(651) 757-2653
Hassan.Bouchareb@state.mn.us

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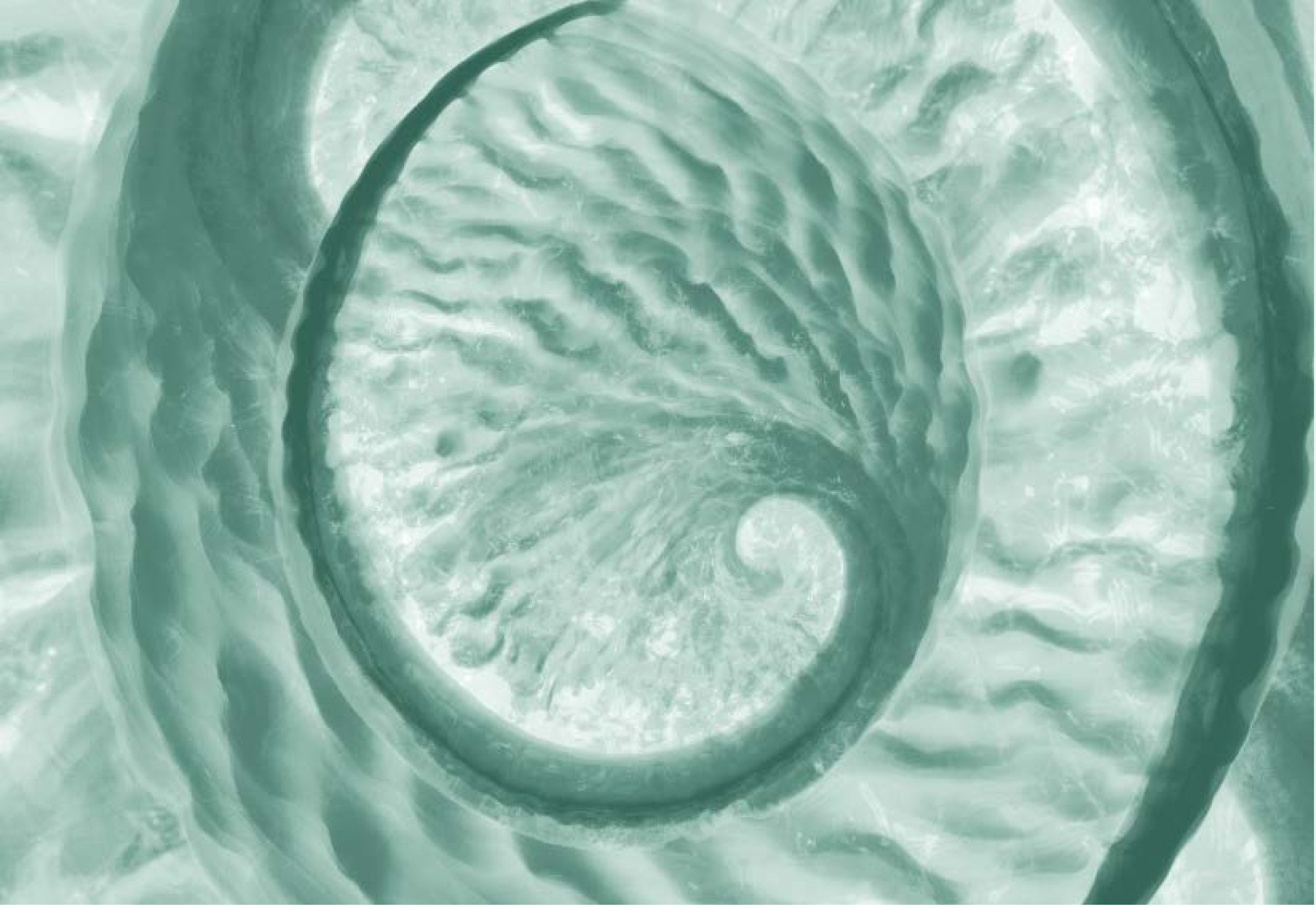
[1] **U.S. Environmental Protection Agency.** *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 20, 2019, https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.



Four Factor Analysis

Hibbing Public Utilities Commission

Hibbing, Minnesota

28 July 2020

Project No.: 0560921

The business of sustainability

ERM

Document details	This document documents the four factor analysis of the sulfur dioxide (SO2) emissions from EQUI 1 and EQUI 3, as well as nitrogen oxide (NOx) emissions from EQUI 1, EQUI 3, and EQUI 7. Hibbing Public Utilities Commission is located in Hibbing, Minnesota.
Document title	Four Factor Analysis
Document subtitle	Hibbing Public Utilities Commission
Project No.	0560921
Date	28 July 2020
Version	Final
Author	Curnow
Client Name	City of Hibbing

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Acronyms and Abbreviations

Name	Description
°F	degrees Fahrenheit
BACT	Best Available Control Technology
CEM	continuous emission monitor
CFR	Code of Federal Regulations
CO	carbon monoxide
DSI	dry sorbent injection
ESP	electrostatic precipitator
FGD	Flue Gas Desulfurization
HPUC	Hibbing Public Utilities Commission
hr	hour
ICAC	Institute of Clean Air Companies
kW	kilowatts
LAER	Lowest Achievable Emission Rate
lb	pounds
LNB	Low NO_x Burner
LSD	Lime Spray Dryer
LSFO	Limestone Forced Oxidation
MMBtu	million British thermal units
MPCA	Minnesota Pollution Control Agency
MW	megawatts
NO_x	nitrogen oxide
NSR	New Source Review
O&M	operation and maintenance
OFA	over-fire air
RBLC	RACT/BACT/LAER Clearinghouse
SCR	Selective Catalytic Reduction
SDA	spray dyer absorber
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
tpy	tons per year
USEPA	U.S. Environmental Protection Agency
WFGD	Wet Flue Gas Desulfurization

1. INTRODUCTION

Under 40 Code of Federal Regulations Part 52 (40 CFR 52) Subpart P Section 51.308, states are required to develop a long-term strategy for regional haze. Each State must submit a long-term strategy that addresses regional haze visibility impairment for each mandatory Class I Federal area within the State and for those areas located outside the State that may be affected by emissions from within the State. The long-term strategy must include the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress toward achieving natural visibility conditions in the affected Class I Federal area.

40 CFR 52 Subpart P, Section 51.308(f)(2)(i) requires the State to evaluate and determine the emission reduction measures that are necessary to make reasonable progress by considering four factors:

1. Cost of compliance,
2. Time necessary for compliance,
3. Energy and non-air quality environmental impacts of compliance, and
4. Remaining useful life of any potentially affected emission unit.

The State Implementation Plan must include a description of the criteria it used to determine which sources or groups of sources it evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy. In considering the time necessary for compliance, if the State concludes that a control measure cannot reasonably be installed and become operational until after the end of the implementation period, the State may not consider this fact in determining whether the measure is necessary to make reasonable progress. Revisions to the Minnesota Regional Haze Implementation Plan are due to the U.S. Environmental Protection Agency (USEPA) by July 31, 2021, and the implementation period is 10 years to demonstrate progress toward attaining the visibility goals.

In a letter dated February 14, 2020, the Minnesota Pollution Control Agency (MPCA) requested that the Hibbing Public Utilities Commission (HPUC) conduct a four-factor analysis of the nitrogen oxide (NO_x) and sulfur dioxide (SO_2) emissions from Boiler 1A (EQUI 1 / EU 001), Boiler 3A (EQUI 3 / EU 003) and Wood-Fired Boiler EQUI 7 (EU007). Boiler 2A (EQUI 2 / EU002) has a common stack with Boiler 1A but was not part of the Four Factor Analysis request. In a telephone conversation with the MPCA Regional Haze contact, Mr. Hassan Bouchareb, ERM was informed that Boiler 2A was not in the request because the base year triggering the review was 2016, and Boiler 2A did not operate in 2016.

The Class 1 areas in proximity to HPUC are Boundary Waters Canoe Area Wilderness and Voyageurs National Park. The center of the Boundary Waters Canoe Area Wilderness is approximately 75 miles from HPUC, and its closest point is approximately 43 miles from HPUC. The center of Voyageurs National Park is approximately 73 miles from HPUC, and its closest point is approximately 64 miles from HPUC. A site location map showing HPUC relative to the two Class 1 areas is provided in Appendix A.

This report documents the four-factor analysis for controlling SO_2 and NO_x from Boiler 1A and Boiler 3A as well as controlling NO_x emissions from the Wood Fired Boiler (EQUI 7) at HPUC. For the rest of this analysis, references to Boiler 1A and 3A will be based on the MPCA air permit identification of these sources, which are EQUI 1 and EQUI 3, respectively. A brief description of HPUC and boiler actual emissions is provided in Section 2 of this report. Section 3 of this report includes the four-factor analysis. The following information is included in Section 3.

- Technically feasible control technology available for NO_x reductions and the cost of control.
- The time schedule necessary for implementing a control strategy is described in general terms accounting for project approval, engineering design, bidding, procurement/contracting, construction, and commissioning.
- The non-air quality impacts of compliance are identified and costs estimated to the extent possible. These include truck traffic, electrical use, solid waste generation, and water use.
- The remaining useful life of the boilers is discussed in terms of the maintenance of the unit and projects for the remaining life of the unit before a major overhaul or replacement is due.
- A general discussion of cost effectiveness is included in the summary section. This discussion is based on a review of published information on the reasonableness cost per ton of SO_2 and NO_x removed as related to visibility improvement.

2. PLANT DESCRIPTION

The HPUC operates a co-generation facility for the city of Hibbing. The facility has the ability to generate electricity and steam. Currently, the facility is not generating electricity and solely providing steam to their steam distribution system for space heating and industrial purposes to nearby businesses, schools, and residences. The HPUC is considered a district heating plant and is located in downtown Hibbing, in close proximity to its steam customers.

HPUC operates in accordance with a federal 40 CFR Part 70 Permit number 13700027-101, issued on May 8, 2018. The combustion emission units at the facility consist of three coal-fired boilers EQUI 1, EQUI 2, EQUI 3, and wood-fired boiler EQUI 7. Attached to the steam distribution system, but not at the main HPUC facility, are two small natural gas fired boilers capable of serving the Hibbing High School. The high school boilers have not been operated in years.

EQUI 7 was permitted in 2005 and was required to demonstrate Best Available Control Technology (BACT) and compliance with the National Ambient Air Quality Standards in place at that time (Permit No. 13700027-003). A gas burner was permitted (Permit No. 13700027-009) and installed in 2015 to assist in stabilizing combustion to lower carbon monoxide (CO) emissions. The natural gas burners were needed to counteract the fluctuation of the moisture content of the wood fuel being received, which was causing swings that led to CO emissions exceeding permit limits too frequently.

EQUI 7 uses selective non-catalytic reduction (SNCR) for NO_x control and a multi-cyclone followed by an electrostatic precipitator (ESP) for particulate matter control. The boiler is also equipped with an opacity monitor, NO_x monitor, and CO monitor. The boiler design includes over-fire air (OFA), which will reduce the formation of NO_x but was not specifically included for NO_x control and is not listed in the air permit as control for NO_x. Additional information on the existing OFA system is in subsequent paragraphs.

HPUC no longer holds a power purchase agreement with Xcel Energy. Currently, HPUC has no intention of generating electricity. Going forward, HPUC will operate in a similar manner as how the facility was operated in the past year, which is not operating the wood boiler, limiting coal to one trainload a season (14,000 tons), and burning natural gas as needed to satisfy district steam loads.

2.1 SO_2 and NO_x Emissions

A summary of recent continuous emission monitor information is listed in Table 1.

Table 1: Continuous Emission Monitor

Value Description	EQUI 1 and EQUI 2 SO_2 (lb/MMBtu)	EQUI 3 SO_2 (lb/MMBtu)	EQUI 7 NO_x (lb/MMBtu)
Minimum	0	0	0
Maximum	0.47 [a]	0.52 [a]	0.155 [b]
Range [c]	0.47	0.52	0.155
Average	0.10	0.17	0.0.03

Abbreviations: lb = pounds; MMBtu = million British thermal units

[a] *Permit limit for each coal-fired boiler (EQUI 1, EQUI 2, and EQUI 3) is 4.0 lbs/MMBtu when combusting coal.*

[b] *Permit limit for EQUI 7 is 0.15 lb/MMBtu based on a 30-day average. The value shown for EQUI 7 in this table is one instance in time, not a 30-day average.*

[c] *Range is the difference between the highest (maximum) and the lowest (minimum) within a set of numbers.*

The potential emissions of SO_2 from EQUI 1 and EQUI 2 are 194 pounds per hour (lb/hr) and 851 tons per year (tpy) each. The potential emissions of SO_2 from EQUI 3 are 223 lb/hr and 978 tpy.

The potential emissions of NO_x from EQUI 1 and EQUI 2 are 140 lb/hr and 612 tpy each. The potential emissions of NO_x from EQUI 3 are 160 lb/hr and 703 tpy. The potential emissions of NO_x for EQUI 7 while burning wood are 34.5 lb/hr and 151.11 tpy.

2.2 Historical SO_2 and NO_x Emissions

Historical emissions were taken from the actual air emission reports HPUC submitted to the MPCA for last 4 years. EQUI 2 was not requested to be included in the analysis by the MPCA, but the boiler shares a common stack with EQUI 1 and so was included for informational purposes. The actual emission rates are based on the continuous emission monitors and are the values reported to the MPCA for the annual actual emission reports.

The actual annual SO_2 emissions have decreased each year from 2016 to 2019. Table 2 provides the actual annual SO_2 emission rates from 2016 to 2019 for each of the coal boilers. The wood boiler EQUI 7 is not included because the amount of sulfur in wood is minimal, which results in minor emissions of SO_2 from the combustion reaction.

Table 2: Historical SO_2 Emissions

Year	EQUI 1 (tpy)	EQUI 2 (tpy)	EQUI 3 (tpy)
2016	167.5	37.3	168.3
2017	181.7	1.2	158.0
2018	83.1	2.15E-14	78.6
2019	3.3	2.15E-14	36.2
Average	108.90	9.63	110.28

The actual annual NO_x emissions have decreased each year from 2016 to 2019. Table 3 provides the actual annual NO_x emission rates from 2016 to 2019 as reported to the MPCA for the three coal boilers and the wood-fired boiler at HPUC.

Table 3: Historical NO_x Emissions

Year	EQUI 1 (tpy)	EQUI 2 (tpy)	EQUI 3 (tpy)	EQUI 7 (tpy)
2016	157.8	39	193.6	87.0
2017	118.9	1.1	167.1	86.8
2018	111.8	1.9E-14	133.3	31.9
2019	43.2	1.9E-14	82.2	15.2
Average	107.93	10.03	144.05	55.23

3. FOUR-FACTOR ANALYSIS

The following is the four-factor analysis. The following subsections present information on the cost of SO_2 and NO_x control for EQUI 1 and EQUI 3 and supplemental NO_x control for EQUI 7. Boiler EQUI 7 already has NO_x control, so the analysis is based on the incremental reduction of changing the control system already in place. The analysis includes the time necessary to implement controls, the energy and non-air quality environmental impacts of implementing controls, and the remaining useful life of the boilers.

3.1 SO_2 Control Technology

A literature review of available control technology for coal fired boilers was conducted and two commercially available Flue Gas Desulfurization (FGD) technology options are available for removing SO_2 produced by coal-fired boilers. The two technologies identified as commercially available that could be applied to EQUI 1 and EQUI 2 are:

1. Limestone Forced Oxidation (LSFO) Scrubber, and
2. Lime Spray Dryer (LSD) Scrubber.

LSFO – LSFO is a wet FGD technology. In a wet system the exhaust gas is mixed with a liquid alkaline sorbent (typically limestone). The mixing is achieved by forcing the exhaust stream through a pool off liquid slurry or by spraying the exhaust with a liquid. This technology is commonly simply referred to as wet scrubbing. According to vendor information, a new wet scrubber can routinely achieve SO_2 removal efficiencies of 95% (Institute of Clean Air Companies [ICAC] Acid Gas/SO_2 Controls), https://www.icac.com/page/Acid_Gas_SO2_Control.

LSD – LSD is a semi-dry FGD technology that uses a spray dyer absorber. In dry FGD systems, the exhaust stream is brought into contact with the alkaline sorbent in a semi-dry state through use of a spray dryer. The removal efficiency is dependent on the amount of sulfur in the coal. This technology is often referred to as dry scrubbing or dry sorbent injection. A fabric filter/baghouse is required downstream of the scrubber to collect the sorbent used to absorb the SO_2. This technology is commonly referred to as a spray dryer.

In addition to the literature review, a search of the USEPA RACT/BACT/LAER Clearinghouse (RBLC) database for Process Type 12.110 Industrial Boiler firing coal and Process Type 11.110 Utility and Large Industrial Boiler firing coal for January 1, 2010 through June 30, 2020 was conducted on June 30, 2020 to identify what SO_2 control strategies are in place and what emission levels represent the BACT. BACT limits are emission rates and are determined on a case-by-case basis. The BACT emission rates are used in this report for comparison purposes only and do not represent an applicable standard.

Eleven plants were listed in the RBLC database; all but one had add-on SO_2 control listed. The only facility with a coal boiler to not list SO_2 control, only an SO_2 limit, was Miller Brewing Company in Ohio. A summary of the RBLC entries for boilers firing coal is attached as Appendix B, the entries specific to SO_2 are in table B-1.

Of the FGD systems installed, 85% are wet systems and 12% are spray dryers. Wet scrubbers can achieve the highest removal efficiencies at greater than 90%, whereas dry scrubbers typically achieve less than 80% (USEPA Fact Sheet).

3.2 NO_x Control Technology

In August 2010 the USEPA published "Documentation for Integrated Planning Model Base Case" that included NO_x emission control information prepared by engineering firm Sargent and Lundy (USEPA 2020) https://www.epa.gov/airmarkets/documentation-integrated-planning-model-ipm-base-case-v410. Sargent and Lundy performed a complete bottom-up engineering reassessment of the cost and performance assumptions NO_x emission controls for large utility boilers.

Available control options identified are:

- Low NO_x Burner (LNB) without OFA,
- LNB with OFA,
- OFA,
- Selective Catalytic Reduction (SCR), and
- SNCR.

3.2.1 Coal-Fired Boilers EQUI 1 and EQUI 3 NO_x Control Technology

The coal-fired boilers at HPUC do not employ any add on control technologies for NO_x reduction. None of the coal-fired boilers have been subject to federal New Source Review (NSR) permitting, which would have required review and installation of BACT.

A search of the RBLC was conducted on June 30, 2020 to identify what NO_x control strategies are in place for coal-fired/natural gas boilers around the country and what emission levels represent the BACT. BACT limits are emission rates and are determined on a case-by-case basis. The BACT emission rates are used in this report for comparison purposes only and do not represent an applicable standard.

An RBLC search for Process Type 12.110 Industrial Boiler firing coal and Process Type 11.110 Utility and Large Industrial Boiler firing coal for January 1, 2010 through June 30, 2020 found 15 entries, which were all for NO_x. Of the 15 entries found, 5 were noted as having SNCR and 3 indicated SCR. A summary of the RBLC entries for boilers firing coal is attached as Appendix B; entries specific to NO_x are in table B-2.

LNB – LNBs control the fuel and air mixture in order to create larger and more branched flames. This reduces the peak flame temperature and in turn reduces NO_x formation.

OFA Systems – Additional NO_x reduction can be achieved by integrating staged combustion (OFA) into the overall system. OFA can be used by itself but is most often used in conjunction with other NO_x reduction systems.

SCR – SCR uses a liquid reducing agent in combination with a catalyst to convert NO_x into nitrogen and water. The reducing agent most commonly used is ammonia.

SNCR – Like the SCR system, SNCR also converts NO_x into nitrogen and water. However, no catalyst is used; instead, the reagent is injected at a high temperature.

3.2.1.1 LNB

EQUI 1 and EQUI 3 are stoker boilers, which means a solid fuel (in this case coal) is mechanically fed into the combustion chamber and the fuel sits on top of a grate during combustion. LNB is not a fuel delivery option for this type of a solid fuel. LNB is not technically feasible and was eliminated from additional discussion for combustion of a solid fuel.

3.2.1.2 OFA

An OFA system is a design feature of boilers to ensure adequate air to promote combustion efficiency. The coal-fired boilers were designed with OFA for proper combustion efficiency. Since OFA is an inherent part of the boiler design, it was not specifically identified as a pollution control technology.

3.2.1.3 SNCR

SNCR reduces the formation of NO_x by injecting an ammonia type reactant into the furnace at a properly determined location. SNCR is used on a wide-range of industrial boilers. SNCR can also accommodate seasonal or year-round boiler operation. Reported SNCR reduction efficiencies vary depending on temperature, residence time, reducing reagent, reagent injection rate, uncontrolled NO_x level, distribution of the reagent in the flue gas, and CO and oxygen concentrations. USEPA “Air Pollution Control Technology Fact Sheet” EPA-452/F-03-031 states that achievable NO_x reduction levels range from 30 to 50% (USEPA 2002). A copy of the USEPA fact sheet is provided in Appendix C.

SCR is the highest-performing control option currently available. According to the USEPA “Air Pollution Control Technology Fact Sheet” for SCR (EPA-452/F-03-032), SCR is capable of NO_x reduction efficiencies in the range of 70 to 90% (ICAC 2000). A copy of the USEPA fact sheet is provided in Appendix D.

3.2.2 Wood-fired Boiler NO_x Control Technology

A BACT analysis was completed for EQUI 7 when it was initially permitted in 2005. That analysis indicated that SNCR and a NO_x emission rate of 0.15 lb per million British thermal units (MMBtu) was BACT. An excerpt from the technical support document that was attached to the operating permit is provided below.

MPCA Technical Support Document, Permit Action Number: 13700028-005 Page 17 of 64, 7/11/2005

> *Nitrogen oxide controls from the RBLC database records indicate a wide range of technologies as BACT, including no control, combustion control, SNCR and SCR. Again the most stringent control, SCR appears in the permit for RBLC record OH-0269, however that facility has not been constructed and the permit has expired. BACT emission rates range from 0.15 to 0.40 pounds per million Btu, excluding OH-0269 which has not been constructed. The lowest BACT emission rate for a constructed and operating facility is 0.15 lbs/MMBtu from the District Energy St. Paul facility, which employs SNCR technology.*

In August 2010, the USEPA published “Documentation for Integrated Planning Model Base Case,” which included NO_x emission control information prepared by engineering firm Sargent and Lundy (USEPA 2020) https://www.epa.gov/airmarkets/documentation-integrated-planning-model-ipm-base-case-v410. Sargent and Lundy performed a complete bottom-up engineering reassessment of the cost and performance assumptions NO_X emission controls for large utility coal fired boilers. The study is not directly relatable to smaller wood boilers, but the identified control technologies available for NO_x control would be the same.

Available control options identified are:

- LNB without OFA,
- LNB with OFA,
- OFA,
- SCR, and
- SNCR.

A new search of the RBLC was conducted on June 30, 2020, to identify what NO_x control strategies are in place for wood-fired/natural gas boilers around the country and what emission levels represent the BACT. BACT limits are emission rates and are determined on a case-by-case basis. The BACT emission rates are used in this report for comparison purposes only and do not represent an applicable standard.

An RBLC search for Process Type 12.120 Industrial Boiler Firing Biomass (includes wood and wood waste) and Process Type 11.120 Utility and Large Industrial Boiler firing Biomass (includes wood and wood waste) for January 1, 2010 through June 30, 2020 found 19 entries. Of the 19 entries found, 10 were noted as having SNCR and 7 indicated SCR. Of the seven entries that indicated SCR was being used for control, only one—Berlin Station LLC, which has a rated capacity of 1,013 MMBtu/hr (over four times larger than EQUI 7)—has been built and is operating. The Berlin Station boiler was the only boiler able to be confirmed to have been built with SCR. The boiler was required to comply with the Lowest Achievable Emission Rate (LAER) requirements. The boiler is noted as having SCR much larger in capacity (464 to 1,200 MMBtu/hr) than EQUI 7 (230 MMBtu/hr). The other entries found were listed as having LNBs. Some boilers also indicated OFA as part of the boiler design. A summary of the RBLC entries is attached as Appendix B, with specific entries for wood-fired boilers listed in table B-3.

LNB – LNBs control the fuel and air mixture in order to create larger and more branched flames. This reduces the peak flame temperature and in turn reduces NO_x formation.

OFA – Additional NO_x reduction can be achieved by integrating staged combustion (OFA) into the overall system. OFA can be used by itself but is most often used in conjunction with other NO_x reduction systems.

SCR – SCR uses a liquid reducing agent in combination with a catalyst to convert NO_x into nitrogen and water. The reducing agent most commonly used is ammonia.

SNCR – Like the SCR system, SNCR also converts NO_x into nitrogen and water. However, no catalyst is used; instead the reagent is injected at a high temperature.

3.2.2.1 LNB

The wood-fired boiler is a stoker boiler which means a solid fuel (in this case wood) is mechanically fed into the combustion chamber and the fuel sits on top of a grate during combustion. The wood that is added is in chip form which is around 3 inches in size. LNB is not a fuel delivery option for this type of a solid fuel. LNB is not technically feasible and was eliminated from additional discussion for wood combustion.

The natural gas burners, installed in 2015 to stabilize combustion, are LNB. Combustion stabilization is necessary due to the variability in the moisture content of the wood, which was causing large swings in CO emissions. Natural gas is not the primary fuel, and as such not the focus of this analysis.

3.2.2.2 OFA

An OFA system is a design feature of boilers to ensure adequate air to promote combustion efficiency. In boiler EQUI 7, air for combustion is supplied from two separate sources: undergate air and OFA. The undergate air supplies 60% of the required combustion air, while the OFA makes up the remaining 40%. The OFA system provides combustion air to a serious of fixed nozzles that penetrate the furnace front and rear walls. There are three elevations of nozzles on the front wall and four elevations of nozzles on the rear wall. The nozzles are optimized to inject air above the grate into a zone where suspension burning takes place. Different nozzle elevations are used to optimize combustion while minimizing emissions from combustion. Both systems are required to be operating when wood is being combusted.

A portion of the operator’s manual provided by Foster Wheeler, which provides a detailed description of the OFA system, is provided in Appendix E. The air permit for EQUI 7 does not list OFA as a pollution control device because it is considered a factor of boiler design, not an add-on control system.

Compliance with 40 CFR 63 Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters—more commonly referred to as “Boiler MACT”—requires EQUI 7 to be tuned annually. The tune-ups focus on boiler efficiency, which would have an impact on improving air emissions.

3.2.2.3 SNCR

EQUI 7 has an SNCR system for NO_x reduction and, as such, no additional discussion on this technology is provided since it is already in use.

3.2.2.4 SCR

SCR is the highest-performing control option currently available. According to the USEPA “Air Pollution Control Technology Fact Sheet” for SCR (EPA-452/F-03-032), SCR is capable of NO_x reduction efficiencies in the range of 70 to 90% (ICAC 2000). A copy of the USEPA fact sheet is provided in Appendix D. Higher reductions are noted by the USEPA as possible but generally not cost-effective. SCR makes use of a catalyst with ammonia injection. The catalyst improves the efficiency of the chemical reduction of NO_x by ammonia. The SCR is designed to evenly distribute the flow of NO_x across a catalyst surface, and provide thorough mixing of the injected ammonia to facilitate reduction and thus removal of NO_x. The catalyst requires gas at a sufficient temperature for the chemical reaction to occur. The boiler exhaust gas also requires particulate removal prior to the SCR to prevent fouling of the catalyst.

The potential use of SCR for control of NO_x from the EQUI 7 was evaluated as BACT when the boiler was originally permitted in 2005. The BACT analysis completed as part of the 2005 permit action indicated that SCR was an infeasible NO_x control option for a wood-fired boiler. The reason the technology was considered infeasible was because of the higher levels of silicates and other constituents found in biomass fuels, which lead to rapid fouling of the catalyst bed, greatly reducing the effectiveness of the SCR system and leading to significant downtime and expense in replacing the catalyst.

The RBLC did note some wood-fired boilers that have been permitted with SCR. The boilers listed as using SCR for NO_x control are all much larger than EQUI 7 and, most likely, operate at a higher capacity factor. Two of the entries that cited SCR noted the basis for the technology as a requirement to permit at LAER. EQUI 7’s primary function at HPUC is to serve the district heating system. HPUC does have some demand for steam in the summer but the majority of the steam production is during the heating season. The HPUC steam customer base continues to decrease as some former entities are relocating outside of the service area or transitioning to their own on-site steam production/heat production.

3.3 Cost Summary

3.3.1 Coal-Fired Boilers EQUI 1A and 3A

3.3.1.1 SO_2 Control Costs

The costs for SO_2 control are based on USEPA published information taken from the USEPA "Air Pollution Control Technology Fact Sheet" EPA-452/F-03-034 for FGD, a copy of which is in Appendix F. The cost information from the fact sheet is contained in table 1b – Summary of Cost Information in $/kilowatts (kW) (2001 Dollars). The table entry for Industrial Coal Boilers was used for EQUI 1 and EQUI 3. Where cost values have been provided as ranges, the average of the range has been used for estimating purposes.

If a spray dryer technology is used a fabric filter will need to be added downstream of the scrubber to remove the sorbent that was injected in to the exhaust stream. The particulate collector is designed and operated as an integral part of the removal process as the solids continue to react with SO_2,

The level of SO_2 reductions are based on the actual annual emissions over the past 4 years. Because the facility is no longer producing electricity and district heating customers continue to decline, the operation of the boilers has trended downward. HPUC expects that the trend for decreased operation will become the normal operating mode going forward. As stated earlier, HPUC is only expecting to purchase one unit train of coal for winter operation. The results of the cost estimating for both wet and spray dry technology are shown in Table 4.

Table 4: EQUI 1 and EQUI 3 SO_2 Control Cost Estimate Summary

Parameter	EQUI 1 (17.8 MW, 178,000 kW)		EQUI 3 (21.4 MW, 214,000 kW)	
	Wet	**Spray Dry**	**Wet**	**Spray Dry**
Capital Cost (875 $/kW for wet and 675 $/KW for spray dry)	$155,750,000	$120,150,000	$187,250,000	$144,450,000
O&M Cost (14 $/kW for wet and 155 $/KW for spray dry)	$2,492,000	$27,590,000	$2,996,000	$33,170,000
Annual Cost (125 $/kW for wet and 275 $/KW for spray dry)	$22,250,000	$48,950,000	$26,750,000	$58,850,000
Subtotal (2001 $)	$180,492,000	$196,690,000	$216,996,000	$236,470,000
Subtotal Adjusted for 2020 $ [a]	$265,738,372	$289,586,687	$319,483,211	$348,154,781
Emission Reduction Percent	90%	80%	90%	80%
Emission Reduction [b] (tpy)	98.01	87.12	99.25	88.22
Cost of Emission Reduction ($/ton) [c]	**$2,711,339**	**$3,323,998**[d]	**$3,218,974**	**$3,946,438**[d]

Abbreviations: MW = megawatts; O&M = operation and maintenance

[a] *The inflation rate in the United States between 2001 and today is 47.23%, (U.S. Bureau of Labor Statistics), https://www.bls.gov/data/inflation_calculator.htm, July 2020.*

[b] *Emission reduction is based on a 4-year average of actual emissions reported from 2016–2019. Emissions of 108.90 tons of SO_2 are from EQUI 1 and 110.28 tons of SO_2 are from EQUI 3.*

[c] *Cost of emission reduction is rounded to the nearest whole dollar.*

[d] *Cost of emission reduction does not include the addition of a fabric filter down stream of the spray dryer.*

3.3.1.2 NO_x Control SNCR Cost

Table 5 summarizes the cost of retrofitting EQUI 1 and EQUI 3 with an SNCR NO_x control system. Costs are based on the USEPA “Air Pollution Control Technology Fact Sheet” for SNCR, EPA-452/F-03-031, page 2, a copy of which is in Appendix C. Information is in \$/MMBtu/hr and \$/megawatts (MW) (1999 Dollars). The excerpt from the fact sheet concerning SNCR costs for industrial boilers greater than 100 MMBtu/hr is presented below.

1. Capital Cost: 900 to 2,500 \$/MMBtu/hr (9,000 to 25,000 \$/MW)
2. Operation and Maintenance (O&M) Cost: 100 to 500 \$/MMBtu/hr (1,000 to 5,000 \$/MW)
3. Annualized Cost: 300 to 1,000 \$/MMBtu/hr (3,000 to 10,000 \$/MW)

EQUI 1 is 17.8 MW and EQUI 3 is 21.4 MW. SNCR is applicable to boilers operated full time as well as boilers only operated on a seasonal basis.

Table 5: EQUI 1 and EQUI 3 SNCR NO_x Control Cost Estimate Summary

Parameter	EQUI 1 (17.8 MW/216 MMBtu/hr)	EQUI 3 (21.4 MW/248 MMBtu/hr)
Capital Cost (17,000 \$/MW)	\$302,600	\$363,800
O&M Cost (3,000 \$/MW)	\$103,500	\$64,200
Annual Cost (6,500 \$/MW)	\$115,700	\$139,100
SNCR Subtotal (1999 \$)	\$521,800	\$567,100
SNCR Subtotal Adjusted for 2020 \$ [a]	\$818,756	\$889,837
Emission Reduction Percent	40%	40%
Emission Reduction [b] (tpy)	43.17	57.62
Cost of Emission Reduction [c] (\$/ton)	\$18,966	\$15,443

[a] *The inflation rate in the United States between 1999 and today is 56.91%, (U.S. Bureau of Labor Statistics, https://www.bls.gov/data/inflation_calculator.htm, July 2020.*

[b] *Emission reduction is based on a 4-year actual average of 2016–2019 emissions of 107.93 tons of* NO_x *from EQUI 1 and 144.05 tons of* NO_x *from EQUI 3.*

[c] *Cost of emission reduction is rounded to the nearest whole dollar.*

The cost to retrofit EQUI 1 and EQUI 3 with SNCR would be about \$19,000 and \$15,500 per ton of NO_x removed. Since the dissolution of the Xcel Power Purchase Agreement and the decline in steam customers, HPUC has seen a reduction in use of all the boilers on site, as evident in the summary of historical NO_x actual emissions contained in Table 3.

3.3.1.3 NO_x Control SCR Cost

The costs for NO_x control are based on USEPA published information taken from the USEPA “Air Pollution Control Technology Fact Sheet” for SCR, EPA-452/F-03-032, a copy of which is in Appendix D. The cost information from the fact sheet is contained in table 1a – Summary of Cost Information in \$/MMBtu/hr (1999 Dollars). The table entry for Industrial Coal Boilers was used for EQUI 1 and EQUI 3. Where cost values have been provided as ranges, the average of the range has been used for estimating purposes. The control efficiency of SCR is based on an 85% capacity factor and annual control of NO_x. Table 6 summarizes the costs associated with retrofitting EQUI 1 and EQUI 3 with SCR for NO_x Control.

Table 6: EQUI 1 and EQUI 3 SCR NO_x Control Cost Estimate Summary

Parameter	EQUI 1 (216 MMBtu/hr)	EQUI 3 (248 MMBtu/hr)
Capital Cost (12,500 $/MMBtu)	$2,700,000	$3,100,000
30% Retrofit Add-on	$810,000	$930,000
O&M Cost (300 $/MMBtu)	$64,800	$74,400
Annual Cost (1,600 $/MMBtu)	$345,600	$396,800
SCR Subtotal (1999 $)	$3,920,400	$4,501,200
SCR Subtotal Adjusted for 2020 $ [a]	$6,151,500	$7,062,833
Pre-heater for Exhaust	Cost Not Available [b]	Not Applicable
Emission Reduction Percent	85%	85%
Emission Reduction [c] (tpy)	91.74	122.44
Cost of Emission Reduction [d] ($/ton)	$67,054	$57,684

[a] *The inflation rate in the United States between 1999 and today is 56.91%, (U.S. Bureau of Labor Statistics), https://www.bls.gov/data/inflation_calculator.htm, July 2020.*

[b] *EQUI 1 would require a preheater for exhaust in lieu of a hot side ESP. The cost for the preheater was not available but is listed in the table in order to identify it as another cost with both capital and operating impacts.*

[c] *Emission reduction is based on actual average emissions from 2016–2019 of 107.93 tons of NO_x from EQUI 1 and 144.05 tons of NO_x from EQUI 3.*

[d] *Cost of emission reduction is rounded to the nearest whole dollar.*

The cost to retrofit EQUI 1 with SCR would be about $67,068 per ton of NO_x removed. That value does not include the cost to increase the heat of the ESP exhaust to a sufficient temperature for the catalyst. The cost to retrofit EQUI 3 with SCR would be about $57,684 per ton of NO_x removed. EQUI 3 uses a hot side ESP, which means the exhaust temperature may be high enough without additional heating for the catalyst reaction.

USEPA directly states that capital costs for SCR are significantly higher than other types of NO_x controls due to the large volume of catalyst that is required. The cost of the catalyst is listed as $283/cubic foot. In addition, retrofitting SCR to an existing unit can increase costs by over 30% (USEPA 2002). The space constraints at HPUC would also add costs due to the requirement to relocate items and demolish structures in order to find the space for additional pollution control equipment.

Since the dissolution of the Xcel Power Purchase Agreement for renewable power, all the boilers on site have seen a reduction in use, as evident in the summary of historical actual NO_x emissions contained in Table 3.

3.3.2 Wood-Fired Boiler EQUI 7 Additional NO_x Control

SCR is the only NO_x reduction technology reviewed for cost since EQUI 7 already uses SNCR and the design includes OFA. LNBs are not applicable to wood. The natural gas fired combustion stabilization burners are low NO_x, but the combustion stabilizing burners are not part of this assessment. No other technology was found for application to this boiler system.

In order for an SCR to work on EQUI 7, the current ESP system would need to be replaced with a hot side ESP or, as an alternative, the air stream could be reheated to achieve sufficient temperature for the catalyst reaction. Catalysts require temperatures ranging from 480 degrees Fahrenheit (°F) to 800°F (ICAC 1997). The exhaust temperature entering the existing ESP is at about 400°F and would not be expected to change significantly upon the exit of the ESP.

As indicated earlier, SCR is typically applied to large coal and natural gas fired electrical utility boilers sized larger than what HPUC operates. The fact sheet does say SCR can be effective for large industrial boilers if the capacity factor is high enough. USEPA only refers to applying SCR technology to coal and natural gas fired boilers.

The USEPA directly states that capital costs for SCR are significantly higher than other types of NO_x controls due to the large volume of catalyst that is required. The cost of the catalyst is listed as $283/cubic foot. In addition, retrofitting SCR to an existing unit can increase costs by over 30% (USEPA 2002).

Table 7 summarizes the cost of retrofitting EQUI 7 with an SCR NO_x control system. Costs are based on the USEPA "Air Pollution Control Technology Fact Sheet" for SCR, EPA-452/F-03-032, table 1a – Summary of Cost Information in $/MMBtu/hr (1999 Dollars) for Industrial Oil, Gas, and Wood boilers. EQUI 7 has a rated capacity of 230 MMBtu/hr. The fact sheet is included as Appendix D.

Table 7: EQUI 7 SCR NO_x Control Cost Estimate Summary

Parameter	EQUI 7 (230 MMBtu/hr)
Capital Cost (5,000 $/MMBtu)	$1,150,000
30% Retrofit Add-on	$345,000
O&M Cost (450 $/MMBtu)	$103,500
Annual Cost (700 $/MMBtu)	$161,000
SCR Subtotal (1999 $)	$1,759,500
SCR Subtotal Adjusted for 2020 $ [a]	$2,760,831
Pre-heater for Exhaust [b]	Cost Not Available
Emission Reduction (85% total which is 53.2% above the existing SNCR system at 31.8%)	53.2%
Emission Reduction [c] (tpy)	40.72
Cost of Emission Reduction [d] ($/ton)	$67,800

[a] *The inflation rate in the United States between 1999 and today is 56.91%, (U.S. Bureau of Labor Statistics), https://www.bls.gov/data/inflation_calculator.htm, July 2020)*

[b] *Preheater for exhaust in lieu of a hot side ESP. The cost for the preheater was not available but is listed in the table in order to identify it as another cost with both capital and operating impacts.*

[c] *Emission reduction is based on 2016 emissions of 87.0 tons of NO_x, which could be reduced by an additional 53.2% by retrofitting EQUI 7 with SCR for NO_x reduction.*

[d] *Cost of emission reduction is rounded to the nearest whole dollar.*

The cost to retrofit EQUI 7 with SCR would be about $67,800 per ton of NO_x removed. That value does not include the cost to increase the heat of the ESP exhaust to a sufficient temperature for the catalyst. Since the dissolution of the Xcel Power Purchase Agreement for renewable power, the wood boiler has seen a reduction in use, as evident in the summary of historical actual NO_x emissions contained in Table 3. It is also the intent of HPUC to not operate the wood boiler going forward. At this time, there are no plans to remove boiler EQUI 7 from the operating permit.

3.4 Time to Implement Controls

To implement any of the controls discussed the following steps, and their duration, would need to be completed by HPUC:

- Budgetary design and project approval (12 months);
- Detailed engineering design and bid documents (6 to 9 months);
- Bid solicitation, evaluation, and selection (3 to 4 months);
- Procurement/contracting (3 to 4 months);
- Construction (6 to 10 months); and
- Commissioning (2 to 3 months).

This leads to an overall schedule of 32 to 42 months from concept to operation. HPUC is a governmental institution that requires formal approval from commission for any funding to occur.

3.5 Non-Air Quality Impacts

This section outlines in general terms the non-air quality related impacts that would result from implementing control technologies on the boilers. Table 8 and 9 show the impacts in general terms. For example, SCR for NO_x control (Table 6) uses a catalyst that is made from various ceramic materials, such as titanium oxide or oxides of base metals (such as vanadium, molybdenum, and tungsten), zeolites, or various precious metals. Mining to obtain catalyst materials has environmental implications.

Table 8: Impacts of Potential SO_x Control Technologies

Technology	EQUI 1	EQUI 3
Electrical Energy Consumption	Yes	Yes
Transportation Impacts	Yes	Yes
Solid Waste Generation	Yes	Yes
Increased Water Consumption	Yes	Yes

Table 9: Impacts of Potential NO_x Control Technologies

Technology	EQUI 1 – SNCR or SCR	EQUI 3 – SNCR or SCR	EQUI 7 - SCR
Electrical Energy Consumption	Yes	Yes	Yes
Transportation Impacts	Yes	Yes	Yes
Solid Waste Generation	Yes	Yes	Yes
Increased Water Consumption	Yes	Yes	Yes

In addition, retrofitting any of the boilers with additional emission control equipment will result in greenhouse gas emissions from construction, truck traffic, material manufacturing, and electrical use. Assuming that the electricity to power the control systems is from some fossil fuel-fired generation, then the increased electrical demand would result in greenhouse gas emissions.

3.6 Remaining Useful Life

EQUI 7 began operating in 2006, and the expectation is that it will last about 25 to 30 years with proper maintenance. That means the remaining useful life of EQUI 7 is greater than 10 years. EQUI 1 and EQUI 2 were installed in 1953, and EQUI 3 was installed around 1972. All three of the coal-fired boilers on site are well past what is deemed as a typical useful life. The boilers are continuously maintained with periodic replacement of components on as needed basis. Based on the years of service of the coal-fired boilers at HPUC, they are well beyond the conventional useful life age typically associated with boilers.

4. SUMMARY

The review of available information suggests that the cost criteria for visibility improvement is less than that for BACT; however, the target values for economic feasibility are generally not published and are evaluated on a case-by-case basis. The USEPA "Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period" (EPA-457/P-16-001, July 2016) provides guidance for states to establish control evaluation criteria, such as:

> "*…measures that cost less than $X/ton and that result in either (1) a visibility benefit greater than Y deciview at the most impacted Class I area or (2) cumulative visibility benefits across multiple affected Class I areas greater than Z deciview.*"

4.1 Coal-Fired Boiler – EQUI 1 and EQUI 3 SO_2 Control

Adding SO_2 control to EQUI 1 and/or EQUI 3 at HPUC could be achieved by either installing a wet scrubber or spray dry scrubber. The cost of FGD technology has been calculated at $2,711,339 per ton of SO_2 removed for EQUI 1 and $3,323,998 per ton of SO_2 removed for EQUI 3. The cost of a spray dryer system not included the downstream fabric filter has been calculated to be over $3,218,974 per ton of SO_2 removed for EQUI 1 and over $3,946,438 per ton of SO_2 removed for EQUI 3. Both technologies, based on how the boilers are currently being operated, should be considered cost-prohibitive for visibility protection.

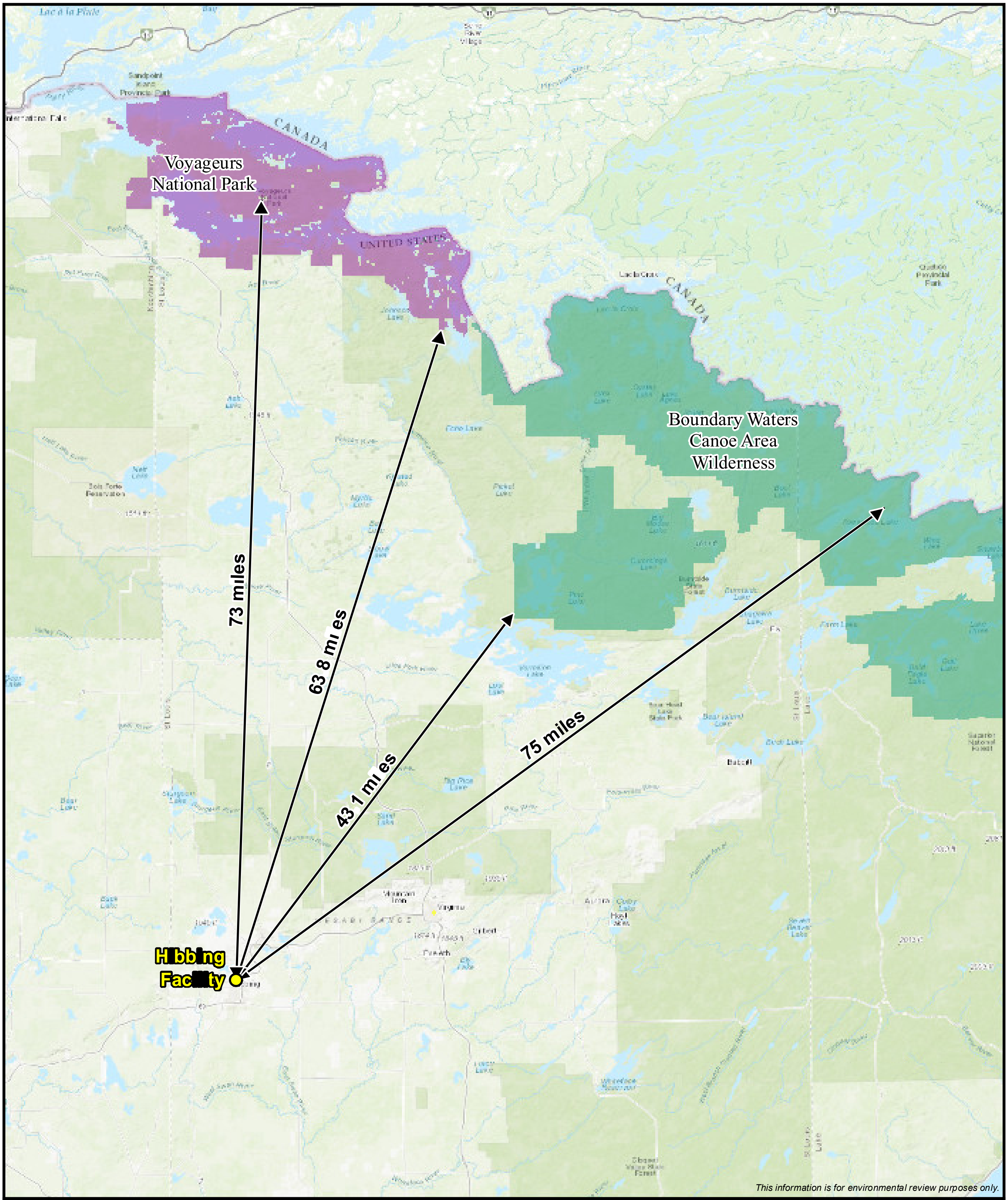
4.2 Coal-Fired Boiler – EQUI 1 and EQUI 3 NO_x Control

Reducing NO_x emissions from the EQUI 1 and/or EQUI 3 at HPUC could be achieved by either installing SNCR or SCR. The cost of SNCR technology has been calculated at $18,966 per ton of NO_x removed for EQUI 1 and $15,443 per ton of NO_x removed for EQUI 3. The cost of an SCR system has been calculated to be over $67,054 per ton of NO_x removed for EQUI 1 and over $57,684 per ton of NO_x removed for EQUI 3. Both technologies, based on how the boilers are currently being operated, should be considered cost-prohibitive for visibility protection.

4.3 Wood Boiler - EQUI 7 NO_x Control

In the case of further reducing NO_x emissions from the EQUI 7 at HPUC, the only available technology would be to replace the SNCR system with SCR. The cost of an SCR system has been calculated to be over $67,800 per ton of NO_x removed. This level of cost effectiveness would not be considered cost-effective for BACT control, and should be considered cost-prohibitive for visibility protection.

APPENDIX A SITE LOCATION MAP



This information is for environmental review purposes only.

● Hibbing Facility
🟩 Boundary Waters Canoe Area Wilderness
🟪 Voyageurs National Park

0 5 10 Miles

Hibbing Public Utilities Commission

Site Location Map

Four Factor Analysis

ERM

M:\Clients\G-I\HPU\Hibbing\ArcGIS\2020\07\Site_Location_Map.mxd | REVISED: 07/08/2020 | SCALE: 1:800,000

DRAWN BY: JSS

APPENDIX B RACT/BACT/LAER SUMMARY

Appendix B-1

Reasonably Available Control Technology, Best Available Control Technology, Lowest Available Emission Rate Clearinghouse

RBLC Database Summary - EPA Database Accessed on June 30, 2020

Coal-Fired Boilers – SO_2

RBLC ID	Company	Boiler Size (MMBtu/hr)	Pollutant	Limit	Units	Technology	Basis For Limit	Permit Issuance Date	Process Type[1]
CA-1206	APMC Stockton Cogen Stockton Cogen Company	730	SO_2	59	lb/hr	Limestone injection with 70% minimum removal efficiency	BACT	9/16/2010	11.110
NE-0037	Cargill, Inc	1500	SO_2	0.11	lb/MMBtu	Limestone injection	BACT	9/8/2006	12.110
OH-0241	Miller Brewing Company	238	SO_2	1.6	lb/MMBtu		BACT	5/27/2004	12.110
VA-0267	VPI University VPI Power Station	146.7	SO_2	23.6	lb/hr	Dry scrubber flue gas desulfurization system, continuous emissions monitoring system (CEMS)	BACT	8/30/2001	12.110
NC-0092	International Paper Company Riegelwood Mill	249	SO_2	0.8	lb/MMBtu	Multiclone, variable throat venturi-type wet scrubber	BACT	5/10/2001	12.110
AZ-0055	Salt River Project Agricultural and Power District Navajo Generator Station	7725	SO_2	0		Flue gas desulfurization	BART	6/6/2012	11.110
MI-0400	Wolverine Power Supply Cooperative, Inc.	3030	SO_2	303	lb/hr	Dry flue gas desulfurization (spray dry absorber or polishing scrubber)	BACT	6/29/2011	11.110
TX-0595	Tenaska Trailblazer Partners, LLC	8307	SO_2	0.06	lb/MMBtu	Wet limestone scrubber	BACT	12/30/2010	11.110
MI-0399	Detroit Edison	7624	SO_2	0.107	lb/MMBtu	Wet flue gas desulfurization	BACT	12/21/2010	11.110
TX-0554	Coleto Creek	6670	SO_2	0.06	lb/MMBtu	Spray Dry Adsorber / Fabric Filter	BACT	5/3/2010	11.110
KY-0100	East Kentucky Power Cooperative, LLC J.K. Smith Generating Station	3000	SO_2	0.075	lb/MMBtu	Limestone Injection (circulating fluidized bed [CFB]) and flash dryer absorber with fresh lime injection	BACT	4/9/2010	11.110

EPA Website: https://cfpub.epa.gov/rblc/index.cfm?action=Search.BasicSearch&lang=en

[1] The process codes searched were 12.100 Industrial-size boilers/furnaces - Solid Fuel & Solid Fuel Mixes (> 100 MMBtu/hr to 250 MMBtu/hr) and 11.120 - Utility - and Large Industrial-Size Boilers/Furnaces (>250 MMBtu/hr) - Biomass (includes wood, wood waste, bagasse, and other biomass).

Notes:

The terms "RACT," "BACT," and "LAER" are acronyms for different program requirements under the NSR program.

RACT, or Reasonably Available Control Technology, is required on existing sources in areas that are not meeting national ambient air quality standards (i.e., non-attainment areas).

BACT, or Best Available Control Technology, is required on major new or modified sources in clean areas (i.e., attainment areas).

LAER, or Lowest Achievable Emission Rate, is required on major new or modified sources in non-attainment areas.

Appendix B-2

Reasonably Available Control Technology, Best Available Control Technology, Lowest Available Emission Rate Clearinghouse

RBLC Database Summary - EPA Database Accessed on June 30, 2020

Coal-Fired Boilers – NO_x

RBLC ID	Company	Boiler Size (MMBtu/hr)	Pollutant	Limit	Units	Technology	Basis For Limit	Permit Issuance Date	Process Type[1]
CA-1206	APMC Stockton Cogen Stockton Cogen Company	730	NO_x	50	ppm	Low bed temperature staged combustion, selective non-catalytic reduction (SNCR)	BACT	9/16/2010	11.110
NE-0037	Cargill, Inc	1500	NO_x	0.08	lb/MMBtu	Combustion control, SNCR	BACT	9/8/2006	12.110
ND-0020	Red Trail Energy, LLC Richardton Plant	250	NO_x	0.1	lb/MMBtu	SNCR	BACT	8/4/2004	12.110
OH-0241	Miller Brewing Company	238	NO_x	0.7	lb/MMBtu	Overfire air (OFA) and side fire air to reduce flame temperature	BACT	5/27/2004	12.110
NC-0092	International Paper Company Riegelwood Mill	249	NO_x	0.4	lb/MMBtu	Good combustion practices	BACT	5/10/2001	12.110
OK-0152	O G and E Muskogee Generating Station	1875.5	NO_x	0.15	lb/MMbtu	Low NO_x burners (LNB) and OFA	BART	1/30/2013	11.110
OK-0151	O G and E Muskogee Generating Station	1875.5	NO_x	0.15	lb/MMbtu	LNBs and OFA	BACT	1/17/2013	11.110
AZ-0055	Salt River Project Agricultural and Power District Navajo Generator Station	7725	NO_x	0.24	lb/MMBtu	LNBs and OFA	BACT	2/6/2012	11.110
MI-0400	Wolverine Power Supply Cooperative, Inc.	3030	NO_x	1	lb/MW-hr	SNCR	BACT	6/29/2011	11.110
TX-0595	Tenaska Trailblazer Partners, LLC	8307	NO_x	0.05	lb/MMBtu	selective catalytic reduction (SCR)	BACT	12/30/2010	11.110
MI-0399	Detroit Edison	7624	NO_x	0.08	lb/MMBtu	Staged combustion, LNBs, OFA, SCR	BACT	12/21/2010	11.110
TX-0554	Coleto Creek	6670	NO_x	0.06	lb/MMBtu	LNBs with OFA system, SCR	BACT	5/3/2010	11.110
KY-0100	East Kentucky Power Cooperative, LLC J.K. Smith Generating Station	3000	NO_x	0.07	lb/MMBtu	SNCR	BACT	4/9/2010	11.110
TX-0557	NRG Texas Power LLC Limestone Electric Generating Station	9061	NO_x	0.25	lb/MMBtu	Tuning of existing low NO_x firing system to induce deeper state combustion	BACT	2/1/2010	11.110
TX-0556	Southwestern Public Service Company Harrington Station Unit 1 Boiler	3630	NO_x	1452	lb/hr	Separated OFA windbox system; LNB tips and additional control to the burners	BACT	1/15/2010	11.110

EPA Website: https://cfpub.epa.gov/rblc/index.cfm?action=Search.BasicSearch&lang=en

[1] The process codes searched were 12.110 Industrial-size boilers/furnaces - Solid Fuel & Solid Fuel Mixes (> 100 MMBtu/hr to 250 MMBtu/hr) Coal (includes bituminous, subbituminous, anthracite, and lignite) and 11.110 - Utility - and Large Industrial-Size Boilers/Furnaces (>250 MMBtu/hr) - Coal (includes bituminous, subbituminous, anthracite, and lilgnite).

Notes:

The terms "RACT," "BACT," and "LAER" are acronyms for different program requirements under the NSR program.

RACT, or Reasonably Available Control Technology, is required on existing sources in areas that are not meeting national ambient air quality standards (i.e., non-attainment areas).

BACT, or Best Available Control Technology, is required on major new or modified sources in clean areas (i.e., attainment areas).

LAER, or Lowest Achievable Emission Rate, is required on major new or modified sources in non-attainment areas.

Appendix B-3

Reasonably Available Control Technology, Best Available Control Technology, Lowest Available Emission Rate Clearinghouse

RBLC Database Summary - EPA Database Accessed on June 30, 2020

Wood-Fired Boilers – NO$_x$

RBLC ID	Company	Boiler Size (MMBtu/hr)	Pollutant	Limit	Units	Technology	Basis For Limit	Permit Issuance Date	Process Type[1]
ME-0040	Robbins Lumber, Inc.	167.3	NO$_x$	25.1	lb/hr	Flue gas recirculation (FGR) / Selective non-catalytic reduction (SNCR)	BACT	6/30/2017	12.120
MI-0425	Arauco North America Grayling Particleboard	110	NO$_x$	95	lb/hr	Good combustion practices, low NO$_x$ burners (LNB)	BACT	5/9/2017	12.120
MI-0421	Arauco North America Grayling Particleboard	110	NO$_x$	95	lb/hr	Good combustion practices, LNB	BACT	8/26/2016	12.120
SC-0149	Klausner Holding USA, Inc.	120	NO$_x$	0.14	lb/MMBtu	SNCR	Other	1/3/2013	12.120
FL-0332	Highlands Envirofuels (HEF), LLC Highlands Biorefinery and Cogeneration Plant	458.5	NO$_x$	0.1	lb/MMBtu	SNCR with urea or NH$_3$ injection, LNB	BACT	9/23/2011	12.120
FL-0322	Southeast Renewable Fuels (SRF), LLC Sweet Sorghum-to-Ethanol Advanced Biorefinery	536	NO$_x$	0.1	lb/MMBtu	Good combustion practices, SNCR, selective catalytic reduction (SCR), or combination with urea or NH$_3$ injection	BACT	12/23/2010	12.120
AR-0161	Sun Bio Material Company	1,200	NO$_x$	0.06	lb/MMBtu	SCR	BACT	9/23/2019	11.120
FL-0359	US Sugar Corporation	1,077	NO$_x$	0.1	lb/MMBtu	SNCR (NH$_3$ injection)	BACT	11/29/2016	11.120
KS-0034	Abengoa Bioenergy Biomass of Kansas (ABBK)	500	NO$_x$	0.3	lb/MMBtu	SCR and overfire air (OFA) system	BACT	5/27/2014	11.120
CA-1225	Sierra Pacific Industries	468	NO$_x$	0.13	lb/MMBtu	SNCR	BACT	4/25/2014	11.120
VT-0039	North Springfield Sustainable Energy Project, LLC	464	NO$_x$	0.03	lb/MMBtu	Bubbling fluidized bed boiler design and SCR	BACT	4/19/2013	11.120
GA-0141	Ogethorpe Power Corporation Warren County Biomass Energy Facility	341	NO$_x$	0.1	lb/MMBtu	SNCR	BACT	12/17/2010	11.120
VT-0037	Beaver Wood Energy Fair Haven, LLC	482	NO$_x$	0.03	lb/MMBtu	Good combustion control and SCR	BACT	2/10/2012	11.120
ME-0037	Verso Bucksport, LLC	817	NO$_x$	0.15	lb/MMBtu	SNCR	BACT	11/29/2010	11.120
CA-1203	Sierra Pacific Industries	335.7	NO$_x$	80	ppm	SNCR	BACT	8/30/2010	11.120
NH-0018	Berlin Station, LLC Burgess Biopower	1,013	NO$_x$	0.06	lb/MMBtu	SCR with NH$_3$ injection[2]	LAER	7/26/2010	11.120
CT-0156	NRG Energy	600	NO$_x$	0.06	lb/MMBtu	Regenerative SCR	LAER	4/6/2010	11.120
AL-0250	Boise White Paper, LLC	435	NO$_x$	0.3	lb/MMBtu	LNB	BACT	3/23/2010	11.120
TX-0553	Lindale Renewable Energy, LLC	1,256	NO$_x$	0.15	lb/MMBtu	SNCR	BACT	1/8/2010	11.120

EPA Website: https://cfpub.epa.gov/rblc/index.cfm?action=Search.BasicSearch&lang=en

[1] The process codes searched were 12.100 Industrial-size boilers/furnaces - Solid Fuel & Solid Fuel Mixes (> 100 MMBtu/hr to 250 MMBtu/hr) and 11.120 - Utility - and Large Industrial-Size Boilers/Furnaces (>250 MMBtu/hr) - Biomass (includes wood, wood waste, bagasse, and other biomass).

[2] This entry is the only facility listed in the RBLC database under the process categories searched, that has been confirmed to have been built and is using an SCR for NO$_x$ control.

Notes:

The terms "RACT," "BACT," and "LAER" are acronyms for different program requirements under the NSR program.

RACT, or Reasonably Available Control Technology, is required on existing sources in areas that are not meeting national ambient air quality standards (i.e., non-attainment areas).

BACT, or Best Available Control Technology, is required on major new or modified sources in clean areas (i.e., attainment areas).

LAER, or Lowest Achievable Emission Rate, is required on major new or modified sources in non-attainment areas.

APPENDIX C USEPA AIR CONTROL TECHNOLOGY SNCR FACT SHEET

EPA-452/F-03-031

Air Pollution Control Technology Fact Sheet

Name of Technology: Selective Non -Catalytic Reduction (SNCR)

Type of Technology: Control Device - Chemical reduction of a pollutant via a reducing agent.

Applicable Pollutants: Nitrogen Oxides (NO_X)

Achievable Emission Limits/Reductions:

NO_X reduction levels range from 30% to 50% (EPA, 2002). For SNCR applied in conjunction with combustion controls, such as low NO_X burners, reductions of 65% to 75% can be achieved (ICAC 2000).

Applicable Source Type: Point

Typical Industrial Applications:

There are hundreds of commercially installed SNCR systems on a wide range of boiler configurations including: dry bottom wall fired and tangentially fired units, wet bottom units, stokers, and fluidized bed units. These units fire a variety of fuels such as coal, oil, gas, biomass, and waste. Other applications include thermal incinerators, municipal and hazardous solid waste combustion units, cement kilns, process heaters, and glass furnaces.

Emission Stream Characteristics:

a. **Combustion Unit Size:** In the United States, SNCR has been applied to boilers and other combustion units ranging in size from 50 to 6,000 MMBtu/hr (5 to 600MW/hr) (EPA, 2002). Until recently, it was difficult to get high levels of NOx reduction on units greater than 3,000 MMBtu (300 MW) due to limitations in mixing. Improvements in SNCR injection and control systems have resulted in high NO_X reductions (> 60%) on utility boilers greater than 6,000 MMBtu/hr (600MW). (ICAC, 2000).

b. **Temperature:** The NO_X reduction reaction occurs at temperatures between 1600°F to 2100°F (870°C to 1150°C) (EPA, 2002). Proprietary chemicals, referred to as enhancers or additives, can be added to the reagent to lower the temperature range at which the NO_X reduction reactions occur.

c. **Pollutant Loading:** SNCR tends to be less effective at lower levels of uncontrolled NO_X. Typical uncontrolled NO_X levels vary from 200 ppm to 400 ppm (NESCAUM, 2000). SNCR is better suited for applications with high levels of PM in the waste gas stream than SCR.

d. **Other Considerations:** Ammonia slip refers to emissions of unreacted ammonia that result from incomplete reaction of the NO_X and the reagent. Ammonia slip may cause: 1) formation of ammonium sulfates, which can plug or corrode downstream components, 2) ammonia absorption into fly ash, which may affect disposal or reuse of the ash, and 3) increased plume visibility. In the U.S., permitted ammonia slip levels are typically 2 to 10 ppm (EPA, 2002). Ammonia slip at these levels do not result in plume formation or pose human health hazards. Process optimization after installation can lower slip levels.

Nitrous Oxide (N_2O) is a by-product formed during SNCR. Urea based reduction generates more N_2O than ammonia-based systems. At most, 10% of the NO_X reduced in urea-based SNCR is converted to N_2O. Nitrous oxide does not contribute to ground level ozone or acid formation. (ICAC,2000)

Emission Stream Pretreatment Requirements: None

Cost Information: All costs are in year 1999 dollars. (NESCAUM, 2000; ICAC, 2000; and EPA, 2002)

The difficulty of SNCR retrofit on existing large coal-fired boilers is considered to be minimal. However, the difficulty significantly increases for smaller boilers and packaged units. The primary concern is adequate wall space within the boiler for installation of injectors. Movement and/or removal of existing watertubes and asbestos from the boiler housing may be required. In addition, adequate space adjacent to the boiler must be available for distribution system equipment and for performing maintenance. This may require modifications to ductwork and other boiler equipment.

A typical breakdown of annual costs for industrial boilers will be 15% to 35% for capital recovery and 65% to-85% for operating expense (ICAC,2000). Since SNCR is an operating expense-driven technology, its cost varies directly with NO_X reduction requirements and reagent usage. Optimization of the injection system after start up can reduce reagent usage and, subsequently, operating costs. Recent improvements in SNCR injection systems have also lowered operating costs.

There is a wide range of cost effectiveness for SNCR due to the different boiler configurations and site-specific conditions, even within a given industry. Cost effectiveness is impacted primarily by uncontrolled NO_X level, required emissions reduction, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty. The cost effectiveness of SNCR is less sensitive to capacity factor than SCR. Control of NO_X is often only required during the ozone season, typically June through August. Since SNCR costs are a function of operating costs, SNCR is an effective control option for seasonal NO_X reductions.

Costs are presented below for industrial boilers greater than 100 MMBtu/hr.

a. **Capital Cost:** 900 to 2,500 $/MMBtu/hr (9,000 to 25,000 $/MW)

b. **O&M Cost:** 100 to 500 $/MMBtu/hr (1,000 to 5,000 $/MW)

c. **Annualized Cost:** 300 to 1000 $/MMBtu/hr (3,000 to 10,000 $/MW)

d. **Cost per Ton of Pollutant Removed:**

Annual Control:	400 to 2,500 $/ton of NO_X removed
Seasonal Control:	2,000 to 3,000 $/ton of NO_X removed

Theory of Operation:

SNCR is based on the chemical reduction of the NO_X molecule into molecular nitrogen (N_2) and water vapor (H_2O). A nitrogen based reducing agent (reagent), such as ammonia or urea, is injected into the post combustion flue gas. The reduction reaction with NO_X is favored over other chemical reaction processes at temperatures ranging between 1600°F and 2100°F (870°C to 1150°C), therefore, it is considered a selective chemical process (EPA, 2002).

Both ammonia and urea are used as reagents. Urea-based systems have advantages over ammonia based systems. Urea is non-toxic, less volatile liquid that can be stored and handled more safely. Urea solution droplets can penetrate farther into the flue gas when injected into the boiler, enhancing the mixing with the flue gas which is difficult in large boilers. However, urea is more expensive than ammonia. The Normalized Stoichiometric Ratio (NSR) defines the ratio of reagent to NO_X required to achieve the targeted NO_X reduction. In practice, more than the theoretical amount of reagent needs to be injected into the boiler flue gas to obtain a specific level of NO_X reduction.

In the SNCR process, the combustion unit acts as the reactor chamber. The reagent is generally injected within the boiler superheater and reheater radiant and convective regions, where the combustion gas temperature is at the required temperature range. The injection system is designed to promote mixing of the reagent with the flue gas. The number and location of injection points is determined by the temperature profiles and flow patterns within the combustion unit.

Certain application are more suited for SNCR due to the combustion unit design. Units with furnace exit temperatures of 1550°F to 1950°F (840°C to 1065°C), residence times of greater than one second, and high levels of uncontrolled NO_X are good candidates.

During low-load operation, the location of the optimum temperature region shifts upstream within the boiler. Additional injection points are required to accommodate operations at low loads. Enhancers can be added to the reagent to lower the temperature range at which the NO_X reduction reaction occurs. The use of enhancers reduces the need for additional injection locations.

Advantages:

- Capital and operating costs are among the lowest of all NO_X reduction methods.
- Retrofit of SNCR is relatively simple and requires little downtime for large and medium size units.
- Cost effective for seasonal or variable load applications.
- Waste gas streams with high levels of PM are acceptable.
- Can be applied with combustion controls to provide higher NO_X reductions.

Disadvantages:

- The waste gas stream must be within a specified temperature range.
- Not applicable to sources with low NO_X concentrations such as gas turbines.
- Lower NO_X reductions than Selective Catalytic Reduction (SCR).
- May require downstream equipment cleaning.
- Results in ammonia in the waste gas stream which may impact plume visibility, and resale or disposal of ash.

References:

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APPENDIX D USEPA AIR CONTROL TECHNOLOGY SCR FACT SHEET

EPA-452/F-03-032

Air Pollution Control Technology
Fact Sheet

Name of Technology: Selective Catalytic Reduction (SCR)

Type of Technology: Control Device - Chemical reduction via a reducing agent and a catalyst.

Applicable Pollutants: Nitrogen Oxides (NOx)

Achievable Emission Limits/Reductions: SCR is capable of NOx reduction efficiencies in the range of 70% to 90% (ICAC, 2000). Higher reductions are possible but generally are not cost-effective.

Applicable Source Type: Point

Typical Industrial Applications: Stationary fossil fuel combustion units such as electrical utility boilers, industrial boilers, process heaters, gas turbines, and reciprocating internal combustion engines. In addition, SCR has been applied to nitric acid plants. (ICAC, 1997)

Emission Stream Characteristics:

a. **Combustion Unit Size:** In the United States, SCR has been applied to coal- and natural gas-fired electrical utility boilers ranging in size from 250 to 8,000 MMBtu/hr (25 to 800 MW) (EPA, 2002). SCR can be cost effective for large industrial boilers and process heaters operating at high to moderate capacity factors (>100 MMBtu/hr or >10MW for coal-fired and >50 MMBtu/hr or >5MW for gas-fired boilers). SCR is a widely used technology for large gas turbines.

b. **Temperature:** The NOx reduction reaction is effective only within a given temperature range. The optimum temperature range depends on the type of catalyst used and the flue gas composition. Optimum temperatures vary from 480°F to 800°F (250°C to 427°C) (ICAC, 1997). Typical SCR systems tolerate temperature fluctuations of ± 200°F (± 90°C) (EPA, 2002).

c. **Pollutant Loading:** SCR can achieve high reduction efficiencies (>70%) on NOx concentrations as low as 20 parts per million (ppm). Higher NOx levels result in increased performance; however, above 150 ppm, the reaction rate does not increase significantly (Environex, 2000). High levels of sulfur and particulate matter (PM) in the waste gas stream will increase the cost of SCR.

d. **Other Considerations:** Ammonia slip refers to emissions of unreacted ammonia that result from incomplete reaction of the NOx and the reagent. Ammonia slip may cause: 1) formation of ammonium sulfates, which can plug or corrode downstream components, and 2) ammonia absorption into fly ash, which may affect disposal or reuse of the ash. In the U.S., permitted ammonia slip levels are typically 2 to 10 ppm. Ammonia slip at this levels do not result in plume formation or human health hazards. Process optimization after installation can lower slip levels.

   Waste gas streams with high levels of PM may require a sootblower. Sootblowers are installed in the SCR reactor to reduce deposition of particulate onto the catalyst. It also reduces fouling of downstream equipment by ammonium sulfates.

The pressure of the waste gas decreases significantly as it flows across the catalyst. Application of SCR generally requires installation a new or upgraded induced draft fan to recover pressure.

Emission Stream Pretreatment Requirements: The flue gas may require heating to raise the temperature to the optimum range for the reduction reaction. Sulfur and PM may be removed from the waste gas stream to reduce catalyst deactivation and fouling of downstream equipment.

Cost Information:

Capital costs are significantly higher than other types of NOx controls due to the large volume of catalyst that is required. The cost of catalyst is approximately 10,000 $\$/m^3$ (283 $\$/ft^3$). A 350 MMBtu/hr natural gas-fired boiler operating at 85% capacity requires approximately 17 m^3 (600 ft^3). For the same sized coal-fired boiler, the required catalyst is on the order of 42 m^3 (1,500 ft^3). (NESCAUM 2000).

SCR is a proprietary technology and designs on large combustion units are site specific. Retrofit of SCR on an existing unit can increase costs by over 30% (EPA, 2002). The increase in cost is primarily due to ductwork modification, the cost of structural steel, and reactor construction. Significant demolition and relocation of equipment may be required to provide space for the reactor.

The O&M costs of using SCR are driven by the reagent usage, catalyst replacement, and increased electrical power usage. SCR applications on large units (>100 MMBtu/hr) generally require 20,000 to 100,000 gallons of reagent per week (EPA, 2002). The catalyst operating life is on the order of 25,000 hours for coal-fired units and 40,000 hours for oil- and gas-fired units (EPA, 2002). A catalyst management plan can be developed so that only a fraction of the total catalyst inventory, rather than the entire volume, is replaced at any one time. This distributes the catalyst replacement and disposal costs more evenly over the lifetime of the system. O&M costs are greatly impacted by the capacity factor of the unit and annual versus seasonal control of NO_X.

O&M cost and the cost per ton of pollutant removed is greatly impacted by the capacity factor and whether SCR is utilized seasonally or year round.

Table 1a: Summary of Cost Information in $/MMBtu/hr (1999 Dollars) [a, b]

Unit Type	Capital Cost ($/MMBtu)	O&M Cost [d] ($/MMBtu)	Annual Cost [d] ($/MMBtu)	Cost per Ton of Pollutant Removed ($/ton)
Industrial Coal Boiler	10,000 - 15,000	300	1,600	2,000 - 5,000
Industrial Oil, Gas, Wood [c]	4,000 - 6,000	450	700	1,000 - 3,000
Large Gas Turbine	5,000 - 7,500	3,500	8,500	3,000 - 6,000
Small Gas Turbine	17,000 - 35,000	1,500	3,000	2,000 - 10,000

Table 1b: Summary of Cost Information in \$/MW (1999 Dollars) [a, b]

Unit Type	Capital Cost (\$/MW)	O&M Cost [d] (\$/MW)	Annual Cost [d] (\$/MW)	Cost per Ton of Pollutant Removed (\$/ton)
Industrial Coal Boiler	1,000 - 1,500	30	160	2,000 - 5,000
Industrial Oil, Gas, Wood [c]	400 - 600	45	70	1,000 - 3,000
Large Gas Turbine	500 - 750	350	850	3,000 - 6,000
Small Gas Turbine	1,700- 3,500	150	300	2,000 - 10,000

[a] (ICAC, 1997; NESCAUM, 2000; EPA, 2002)

[b] Assumes 85% capacity factor and annual control of NOx

[c] SCR installed on wood fired boiler assumes a hot side electrostatic precipitator for PM removal

[d] Coal and oil O&M and annual costs are based on 350MMBtu boiler, and
gas turbine O&M and annual costs are based on 75 MW and 5 MW turbine

Theory of Operation:

The SCR process chemically reduces the NOx molecule into molecular nitrogen and water vapor. A nitrogen based reagent such as ammonia or urea is injected into the ductwork, downstream of the combustion unit. The waste gas mixes with the reagent and enters a reactor module containing catalyst. The hot flue gas and reagent diffuse through the catalyst. The reagent reacts selectively with the NOx within a specific temperature range and in the presence of the catalyst and oxygen.

Temperature, the amount of reducing agent, injection grid design and catalyst activity are the main factors that determine the actual removal efficiency. The use of a catalyst results in two primary advantages of the SCR process over the SNCR: higher NOx control efficiency and reactions within a lower and broader temperature range. The benefits are accompanied by a significant increase in capital and operating costs. The catalyst is composed of active metals or ceramics with a highly porous structure. Catalysts configurations are generally ceramic honeycomb and pleated metal plate (monolith) designs. The catalyst composition, type, and physical properties affect performance, reliability, catalyst quantity required, and cost. The SCR system supplier and catalyst supplier generally guarantee the catalyst life and performance. Newer catalyst designs increase catalyst activity, surface area per unit volume, and the temperature range for the reduction reaction.

Catalyst activity is a measure of the NOx reduction reaction rate. Catalyst activity is a function of many variables including catalyst composition and structure, diffusion rates, mass transfer rates, gas temperature, and gas composition. Catalyst deactivation is caused by:

- poisoning of active sites by flue gas constituents,
- thermal sintering of active sites due to high temperatures within reactor,
- blinding/plugging/fouling of active sites by ammonia-sulfur salts and particulate matter, and
- erosion due to high gas velocities.

As the catalyst activity decreases, NOx removal decreases and ammonia slip increases. When the ammonia slip reaches the maximum design or permitted level, new catalyst must be installed. There are several different locations downstream of the combustion unit where SCR systems can be installed. Most coal-fired applications locate the reactor downstream of the economizer and upstream of the air heater and particulate control devices (hot-side). The flue gas in this location is usually within the optimum temperature window for NOx reduction reactions using metal oxide catalysts. SCR may be applied after PM and sulfur removal

equipment (cold-side), however, reheating of the flue gas may be required, which significantly increases the operational costs.

SCR is very cost-effective for natural gas fired units. Less catalyst is required since the waste gas stream has lower levels of NOx, sulfur, and PM. Combined-cycle natural gas turbines frequently use SCR technology for NOx reduction. A typical combined-cycle SCR design places the reactor chamber after the superheater within a cavity of the heat recovery steam generator system (HRSG). The flue gas temperature in this area is within the operating range for base metal-type catalysts.

SCR can be used separately or in combination with other NOx combustion control technologies such as low NOx burners (LNB) and natural gas reburn (NGR). SCR can be designed to provide NOx reductions year-round or only during ozone season.

Advantages:

- Higher NOx reductions than low-NOx burners and Selective Non-Catalytic Reduction (SNCR)
- Applicable to sources with low NOx concentrations
- Reactions occur within a lower and broader temperature range than SNCR.
- Does not require modifications to the combustion unit

Disadvantages:

- Significantly higher capital and operating costs than low-NOx burners and SNCR
- Retrofit of SCR on industrial boilers is difficult and costly
- Large volume of reagent and catalyst required.
- May require downstream equipment cleaning.
- Results in ammonia in the waste gas stream which may impact plume visibility, and resale or disposal of ash.

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APPENDIX E EXCERPTS FROM FOSTER WHEELER OPERATORS MANUAL

The grate is fed onto the grate by means of two pneumatic fuel distributors situated on the furnace front wall. These are located above the grate and are evenly spaced across the width of the boiler. Each distributor receives litter from a metering feeder and blows it into the furnace using a variable pressure air stream.

The feeders are set up using a pulse air, rotating damper to regulate the front to back fuel trajectory onto the grate. Conveying air used by the feeders is supplied by a separate distributor air fan.

l) Fuel Feeders

The boiler is equipped with two variable speed twin screw feeders that are used to regulate fuel feed to each pneumatic distributor. These are located above and in close proximity to each fuel distributor.

Biomass fuel is metered into the boiler at a controlled rate set by load demand.
The feeders are supplied with integral fuel bins that receive biomass from the plant conveyor.

m) Primary Air System (HTUsee Air & Flue Gas System DescriptionUTH)

A single variable speed motor driven FD fan provides combustion air to the grate. The fan is furnished with an inlet filter, venturi metering section and inlet silencer. Airflow control is split ranged using variable speed with inlet damper control at low load. The output of the fan is regulated from load demand from the combustion control system.

Air discharged from the fan is heated in the undergrate air heater prior to entering the undergrate air plenums.

n) Secondary Air System (TUsee Air & Flue Gas System DescriptionUTH)

A single variable speed motor driven FD fan provides combustion air to the overfire air nozzles above the grate. The fan is furnished with an inlet duct, venturi metering section, intake silencer and inlet control damper. Airflow control is split ranged using variable speed with inlet damper control at low load. The output of the fan is regulated from load demand from the combustion control system.

Discharge air is heated and directed to a series of overfire air nozzles on the front and rear furnace walls.

o) Distributor Air Fan

A single, constant speed distributor air fan is furnished to supply ambient air to the fuel distributors. The fan is set up to supply a constant amount of air and is unregulated by the operator.

General
The following description should be read in conjunction with drawing No. 113925V-0202 Air & Flue Gas P&ID.

Note:
FWL terminal points are designated as "TP FWL".

Combustion Air System
Air for combustion is supplied from two separate sources, undergrate air and overfire air. Each system is sized to deliver approximately 60% and 40% respectively of the required total combustion air. It is necessary that both systems be in operation to operate the boiler when firing biomass fuel.

Undergrate air
The undergrate air system provides combustion air to the under the grate air zones. A forced draft fan delivers ambient air to the grate taken from inside the building via an intake duct. The incoming air stream to the fan is metered through a venturi section 11FE-510, equipped with flow transmitter 11FT 510 (by others) and flow switch 11FSH 510 (by others). An intake silencer 11EDS 511 is furnished for noise attenuation downstream of the metering venturi.

An inlet louver damper 11EJM 511is furnished for low load control of airflow. This is driven by air operated actuator 11FY 510 in response to a 4-20mA control signal from the DCS combustion controls. The actuator is provided with open/closed limit switches 11ZSL510/ZSH 510 for proof of closed and purge positions.

The variable speed undergrate air fan is driven by an electric motor, 11MV 510 equipped with winding temperature thermostats. The fan is also equipped with bearing temperature monitors 11TE 510A/B.

The FD fan is equipped with a variable speed drive for discharge capacity control that is spilt ranged for operation with the inlet louver control damper. Fan speed is controlled from the characterized 4-20mA combustion control signal.

Pressure at the FD fan discharge is monitored by pressure transmitter 11PT 510 prior to being directed through a tubular air heater 11ESE 510 that is utilised to preheat the undergrate air. This is necessary with all high moisture fuels for optimum combustion conditions. The temperature of air leaving the air heater is unregulated and varies with load. Temperature is measured by transmitter 11TT 512.

The grate is divided into three separate air zones from front to back. These, in turn are subdivided into LH and RH sections for a total of six independent zones. Air to each zone can be biased by individual manual inlet dampers. Control of these dampers allows the

operator to manually bias the air split, front to back and side to side for optimum burning and emissions control.

Thermocouples 11TE 721A/B/C & 11TE 722 A/B/C are provided on the underside of the grate for temperature monitoring and alarm purposes.

Overfire Air
The overfire air system provides combustion air to a series of fixed nozzles that penetrate the furnace front and rear walls. There are three elevations of nozzles on the front wall and four elevations on the rear wall (see DSCo. Manual for details). These are optimized during commissioning and set up to inject air above the grate into a zone where suspension burning takes place. Different nozzle elevations are selected in order to provide optimum combustion conditions with minimum emissions.

Secondary air is drawn from inside the boiler building through an intake duct. The duct is equipped with a venturi section 11FE 515 and transmitter 11FT 515 (by others) for flow metering purposes. A silencer 11EDS 510 is provided on the fan intake for noise attenuation purposes.

An inlet louver damper 11EJM 510 is furnished for low load control of airflow. This is driven by air operated actuator 11FY 515 in response to a 4-20mA control signal from the DCS combustion controls. The actuator is provided with open/closed limit switches 11ZSL 515/ZSH 515 for proof of closed and purge positions.

The overfire air fan is driven by a variable speed electric motor 11MV 515 equipped with winding temperature thermostats. The motor is also equipped with bearing temperature detectors TE-A-09-006A/006B.

The fan is equipped with inboard and outboard bearing temperature detectors 11TE 515A/B.

The overfire air fan is equipped with a variable speed drive for discharge capacity control that is spilt ranged for operation with the inlet louver control damper. Fan speed is controlled from the characterized 4-20mA combustion control signal.

Pressure at the overfire air fan discharge is monitored by pressure transmitter 11PT 515 prior to being directed through a tubular air heater 11ESE 511 that is utilised to preheat the overfire air. The temperature of air leaving the air heater is unregulated and varies with load. Temperature is measured by transmitter 11TT 517.

Preheated air is routed through a series of ducts to the front and rear overfire air nozzles into the furnace. Isolation dampers are provided on the nozzles for operational flexibility since some nozzles, or complete nozzle elevations may not be used during normal operation.

APPENDIX F USEPA AIR CONTROL TECHNOLOGY FGD FACT SHEET

EPA-452/F-03-034

Air Pollution Control Technology Fact Sheet

Name of Technology: Flue Gas Desulfurization (FGD) - Wet, Spray Dry, and Dry Scrubbers

Type of Technology: Control Device - absorption and reaction using an alkaline reagent to produce a solid compound.

Applicable Pollutants: Sulfur dioxide (SO_2)

Achievable Emission Limits/Reductions: Scrubbers are capable of reduction efficiencies in the range of 50% to 98%. The highest removal efficiencies are achieved by wet scrubbers, greater than 90% and the lowest by dry scrubbers, typically less than 80%. Newer dry scrubber designs are capable of higher control efficiencies, on the order of 90%.

Applicable Source Type: Point

Typical Industrial Applications: Stationary coal- and oil-fired combustion units such as utility and industrial boilers, as well as other industrial combustion units such as municipal and medical waste incinerators, cement and lime kilns, metal smelters, petroleum refineries, glass furnaces, and H_2SO_4 manufacturing facilities. Approximately 85% of the FGD systems installed in the US are wet systems, 12% are spray dry and 3% are dry systems.

Emission Stream Characteristics:

a. **Combustion Unit Size:** SO_2 scrubbers have been applied combustion units firing coal and oil ranging in size from 5 MW to over 1,500 MW (50 MMBtu/hr to 15,000 MMBut/hr). Dry and spray scrubbers are generally applied to units less than 3,000 MMBtu/hr (300 MW) (EPA, 2000).

b. **Temperature:** For wet scrubbers, typical inlet gas temperatures are 150°C to 370°C (300°F to 700°F) (FETC, 1996). For spray dry systems, the temperature of the flue gas exiting the absorber must be 10°C to 15°C (20°F to 30°F) above the adiabatic saturation temperature. Optimal temperatures for SO_2 removal for dry sorbent injection systems range from 150°C to 180°C (300°F to 350°F). Optimal temperatures for SO_2 removal when applying dry sorbent injection systems vary between 150°C to 1000°C (300°F to 1830°F) depending on the sorbent properties (Joseph, 1998)

c. **Pollutant Loading:** SO_2 scrubbers are limited to dilute SO_2 waste gas streams of approximately 2000 ppm.(Cooper, 2002).

d. **Other Considerations:** The amount of chlorine in the flue gas affects the amount of water evaporated by the system due to the formation of salts. Chlorine content improves the SO_2 removal but also results in salt deposition on the absorber and downstream equipment (Schnelle, 2002).
An additional or upgraded induced draft (ID) fan may be required to compensate for flue gas pressure drop across the absorber.

Many wet systems reheat the flue gas downstream of the absorber to prevent corrosion caused by condensation inside the ducts and stack and reduce plume visibility.

Emission Stream Pretreatment Requirements: In spray dry and dry injection systems, the flue gas must be cooled to a temperature range of 10°C to 15°C (20°F to 30°F) above adiabatic saturation. This temperature range avoids wet solids deposition on downstream equipment and plugging of the baghouse. A heat recovery boiler, an evaporative cooler or a heat exchanger is typically used to cool the gas.

Cost Information:

Capital costs for SO_2 scrubbers have decreased by over 30% since the beginning of the 1990's. Current costs for SO_2 scrubbers applied to electric utilities are reported to be approximately $100/kW (Smith, 2001). Retrofit of scrubbers on existing units can increase the capital cost up to 30%. Retrofit costs vary significantly between sites and depend on space limitations, major modifications to existing equipment (e.g., ductwork and stack) and the operating condition of the units (e.g., temperature, flowrate).

O&M costs increase with increasing sulfur content since more reagent is required to treat the same volume of gas. Typical reagents such as lime and limestone are inexpensive; however, the use of proprietary reagents or reagent enhancers or additives that can significantly increase the O&M cost. Limestone is generally available for 10 to 20 $/ton and lime is available for 60 to 80 $/ton (Smith, 2001). Waste product disposal costs vary from $10/ton to $30/ton and byproduct saleable prices vary from 0 to 15 $/ton (Smith, 2001). The addition of a scrubbers causes a loss of energy available for generating steam due to evaporation of water and the energy required to drive the reaction. New scrubber designs result in an energy penalty of less than 1% of the total plant energy (Srivastava, 2001).

Table 1a: Summary of Cost Information in $/MMBtu/hr (2001 Dollars) [a]

Scrubber Type	Unit Size (MMBtu/hr)	Capital Cost ($/MMBtu)	O&M Cost [b] ($/MMBtu)	Annual Cost ($/MMBtu)	Cost per Ton of Pollutant Removed ($/ton)
Wet	> 4,000	10,000 -25,000	200 - 800	25 - 40	200 - 500
	< 4,000	25,000 - 150,000	800 - 1,800	60 - 600	500 - 5,000
Spray Dry	> 2,000	4,000 - 15,000	600 - 1,000		150 - 300
	< 2,000	30,000 - 150,000	1,000 - 30,000	10,000 - 50,000	500 - 4,000

Table 1b: Summary of Cost Information in $/MW (2001 Dollars) [a]

Scrubber Type	Unit Size (MW)	Capital Cost ($/kW)	O&M Cost [b] ($/kW)	Annual Cost ($/kW)	Cost per Ton of Pollutant Removed ($/ton)
Wet	> 400	100 - 250	2 - 8	20 - 50	200 - 500
	< 400	250 - 1,500	8 - 20	50 - 200	500 - 5,000
Spray Dry	> 200	40 - 150	4 - 10	20 -50	150 - 300
	< 200	150 - 1,500	10 - 300	50 - 500	500 - 4,000

[a] (EIA, 2002; EPA, 2000; Srivastava, 2001)

[b] Assumes capacity factor > 80%

Theory of Operation:

The FDG or SO_2 scrubbing process typically uses a calcium or sodium based alkaline reagent. The reagent is injected in the flue gas in a spray tower or directly into the duct. The SO_2 is absorbed, neutralized and/or oxidized by the alkaline reagent into a solid compound, either calcium or sodium sulfate. The solid is removed from the waste gas stream using downstream equipment.

Scrubbers are classified as "once-through" or "regenerable", based on how the solids generated by the process are handled. Once-through systems either dispose of the spent sorbent as a waste or utilize it as a byproduct. Regenerable systems recycle the sorbent back into the system. At the present time, regenerable processes have higher costs than once-through processes; however, regenerable processes might be chosen if space or disposal options are limited and markets for byproducts (gypsum) are available (Cooper, 2002). In 1998, approximately 3% of FDG systems installed in the US were regenerable.

Both types of systems, once-through and regenerable, can be further categorized as wet, dry, or semi-dry. Each of these processes is described in the following sections.

Wet Systems

In a wet scrubber system, flue gas is ducted to a spray tower where an aqueous slurry of sorbent is injected into the flue gas. To provide good contact between the waste gas and sorbent, the nozzles and injection locations are designed to optimize the size and density of slurry droplets formed by the system. A portion of the water in the slurry is evaporated and the waste gas stream becomes saturated with water vapor. Sulfur dioxide dissolves into the slurry droplets where it reacts with the alkaline particulates. The slurry falls to the bottom of the absorber where it is collected. Treated flue gas passes through a mist eliminator before exiting the absorber which removes any entrained slurry droplets. The absorber effluent is sent to a reaction tank where the SO_2-alkali reaction is completed forming a neutral salt. In a regenerable system, the spent slurry is recycled back to the absorber. Once through systems dewater the spent slurry for disposal or use as a by-product.

Typical sorbent material is limestone, or lime. Limestone is very inexpensive but control efficiencies for limestone systems are limited to approximately 90%. Lime is easier to manage on-site and has control efficiencies up to 95% but is significantly more costly (Cooper 2002). Proprietary sorbents with reactivity-enhancing additives provide control efficiencies greater than 95% but are very costly. Electrical utilities store large volumes of limestone or lime on site and prepare the sorbent for injection, but this is generally not cost effective for smaller industrial applications.

The volume ratio of reagent slurry to waste gas is referred to as the liquid to gas ratio (L/G). The L/G ratio determines the amount of reagent available for reaction with SO_2. Higher L/G ratios result in higher control efficiencies. Higher L/G also increases oxidation of the SO_2, which results in a decrease of the formation of scale in the absorber. O&M costs are a direct function of reagent usage, so increasing the L/G increases annual costs. L/G ratios are approximately 1:1 for wet scrubbers and are expressed as gallons of slurry per 1000 ft^3 of flue gas (liters of slurry/1000Nm^3 of flue gas).

Oxidation of the slurry sorbent causes gypsum (calcium sulfate) scale to form in the absorber. Limestone forced oxidation (LSFO) is a newer process based on wet limestone scrubbing which reduces scale. In LSFO, air is added to the reaction tank which oxidizes the spent slurry to gypsum. The gypsum is removed from the reaction tank prior to the slurry being recycled to the absorber. The recycle slurry has a lower concentration of gypsum and scale formation in the absorber is significantly reduced. Gypsum can be commercially sold, eliminating the need for landfilling of the waste product (Srivastava, 2001). In addition to scale control, the larger size gypsum crystals formed in LSFO settle and dewater more efficiently, reducing the size of the byproduct handling equipment (EPA, 2002). However, LSFO requires additional blowers which increase the capital and annual costs of the system.

Wet limestone scrubbing has high capital and operating cost due to the handling of liquid reagent and waste. Nonetheless, it is the preferred process for coal-fired electric utility power plants burning coal due to the low cost of limestone and SO_2 control efficiencies from 90% up to 98% (Schnelle, 2002).

Semi-Dry Systems

Semi-dry systems, or spray dryers, inject an aqueous sorbent slurry similar to a wet system, however, the slurry has a higher sorbent concentration. As the hot flue gas mixes with the slurry solution, water from the slurry is evaporated. The water that remains on the solid sorbent enhances the reaction with SO_2. The process forms a dry waste product which is collected with a standard particulate matter (PM) collection device such as a baghouse or ESP. The waste product can be disposed, sold as a byproduct or recycled to the slurry.

Various calcium and sodium based reagents can be utilized as sorbent. Spray dry scrubbers typically inject lime since it is more reactive than limestone and less expensive than sodium based reagents. The reagent slurry is injected through rotary atomizers or dual-fluid nozzles to create a finer droplet spray than wet scrubber systems (Srivastava, 2000).

The performance of a lime spray dry scrubber is more sensitive to operating conditions. A “close approach” to adiabatic saturation temperature is required to maximize the removal of SO_2. However, excess moisture causes the wet solids to deposit on the absorber and downstream equipment. The optimum temperature is 10°C to 15°C (20°F to 50°F) below saturation temperature (Srivastava, 2000). Lower L/G ratios, approximately 1:3, must be utilized do to the limitation on flue gas moisture (Schnelle, 2002). Flue gas with high SO_2 concentrations or temperatures reduce the performance of the scrubber (Schnelle, 2002).

SO_2 control efficiencies for spray dry scrubbers are slightly lower than wet systems, between 80% and 90% due to its lower reactivity and L/G ratios. Application of a single spray dry absorber is limited to combustion units less than 200 MW (2,000 MMBtu/hr) (IEA, 2001). Larger combustion units require multiple absorber systems. The capital and operating cost for spray dry scrubbers are lower than for wet scrubbing because equipment for handling wet waste products is not required. In addition, carbon steel can be used to manufacture the absorber since the flue gas is less humid. Typically applications include electric utility units burning low- to medium- sulfur coal, industrial boilers, and municipal waste incinerators that require 80% SO_2 control efficiency (Schnelle, 2002).

Dry systems

Dry sorbent injection systems, pneumatically inject powdered sorbent directly into the furnace, the economizer, or downstream ductwork. The dry waste product is removed using particulate control equipment such as a baghouse or electrostatic precipitator (ESP). The flue gas is generally cooled prior to the entering the PM control device. Water can be injected upstream of the absorber to enhance SO_2 removal (Srivastava, 2001).

Furnace injection requires flue gas temperatures between 950°C to 1000°C (1740°F to 1830°F) in order to decompose the sorbent into porous solids with high surface area (Srivastava 2001). Injection into the economizer requires temperatures of 500°C to 570°C (930°F to 1060°F) (Srivastava 2001). Duct injection requires the dispersion of a fine sorbent spray into the flue gas downstream of the air preheater. The injection must occur at flue gas temperatures between 150°C to 180°C (300°F to 350°F) (Joseph, 1998).

Dry sorbent systems typically use calcium and sodium based alkaline reagents. A number of proprietary reagents are also available. A typical injection system uses several injection lances protruding from the furnace or duct walls. Injection of water downstream of the sorbent injection increases SO_2 removal by the sorbent.

An even distribution of sorbent across the reactor and adequate residence time at the proper temperature are critical for high SO_2 removal rates (Srivastava 2001). Flue gas must be kept 10°C to 15°C (20°F to 50°F) below saturation temperature to minimize deposits on the absorber and downstream equipment.

Dry scrubbers have significantly lower capital and annual costs than wet systems because they are simpler, demand less water and waste disposal is less complex. Dry injection systems install easily and use less space, therefore, they are good candidates retrofit applications. SO_2 removal efficiencies are significantly lower than wet systems, between 50% and 60% for calcium based sorbents. Sodium based dry sorbent injection into the duct can achieve up to 80% control efficiencies (Srivastava 2001). Dry sorbent injection is viewed as an emerging SO_2 control technology for medium to small industrial boiler applications. Newer applications of dry sorbent injection on small coal-fired industrial boilers have achieved greater than 90% SO_2 control efficiencies.

Advantages:

- High SO_2 removal efficiencies, from 50% up to 98%.
- Products of reaction may be reusable
- Difficulty of retrofit is moderate to low
- Inexpensive and readily available reagents

Disadvantages:

- High capital and O&M costs
- Scaling and deposit of wet solids on absorber and downstream equipment
- Wet systems generate a wet waste product and may result in a visible plume
- Cannot be used for waste gas SO_2 concentrations greater than 2,000 ppm
- Disposal of waste products significantly increases O&M costs

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HIBBING PUBLIC UTILITIES COMMISSION

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Date: June 18, 2021

To: Hassan M. Bouchareb, Engineer
Minnesota Pollution Control Agency (MPCA)
Environmental Analysis & Outcomes Division
520 Lafayette Road
St. Paul, MN | 55155

CC: Ann Curnow, Senior Consultant ERM

From: Luke J. Peterson, General Manager
Hibbing Public Utilities

Re: **Regional Haze – 4 Factor Analysis and Response to Comments of 4-Factor Analysis for Hibbing Public Utilities**

Dear Hassan;

This memorandum is in response to the April 19, 2021 email and subsequent phone conference call concerning the comments on the 4-Factor Regional Haze Analysis completed for Hibbing Public Utilities Commission (HPUC) and submitted to the Minnesota Pollution Control Agency (MPCA) on July 28, 2020.

The questions and comments came from three entities. The MPCA, the United States Environmental Protection Agency (USEPA) and the Federal Land Managers (FLM).

The questions/comments that were requested to be addressed fall in to the following areas:

1. Operating Conditions
    a. Allowable Fuels
    b. Future Operations
2. Emission Unit Data Request
    a. Additional CEM Data
    b. Projected Emissions
3. Four Factor Analysis
    a. Retrofit Factor
    b. Confirmation that analysis for 1A can be used for 2A (these boilers share a common stack and are identical in size)

c. Considered lowering the permitted allowable facility-wide sulfur dioxide limit of 4 lbs/hour when combusting coal.

Since the original analysis was submitted in July of 2020 the inflation rate has increased and the cost to install control equipment has increased as a result.

<u>Operating Conditions</u>

Under the direction of a new General Manager, HPUC is currently reviewing its operations and assessing options for achieving the utility's sustainability goals. HPUC is developing goals aimed at providing steam and electricity to the City of Hibbing residents at a reasonable cost using a method that achieves self-reliance and reduces environmental impact for more sustainable, locally produced energy and heat. The extreme cold that affected the southern parts of the United States last winter highlighted in a painful economic way the cost of dependence on markets and natural gas delivery infrastructure to provide life sustaining heat to in Hibbing in the coldest parts of the winter.

HPUC was caught in the soaring cost of natural gas. That cost of the natural gas spike had to be passed on to the utility customers, many of which live below the poverty level.

The MPCA and the FLM requested additional detail and timing on

1. Restricting coal usage at HPUC,
2. Decommissioning the wood boiler, and
3. No longer using coal in EQUI 2 (Boiler 2A).

Because of the retooling of its operations, HPUC is not in a position to predict its future operation or fuel mix at this time. Even so, HPU is embarking on pilot season of burning biomass fuel for the 2021/2022 heating season for the purposes of gather more data and optimizing sustainability operations for future growth. Once more specific plans are made, HPUC will advise the MPCA and revise the operating permit accordingly.

Emission Unit Data

HPUC completes weekly coal sampling which includes the sulphur content percent by weight. Five sampling events from January 2021 were reviewed and the weight percent of sulphur ranged from 0.29% to 0.33% by weight. For that time period the average equates to 0.31% by weight. SO_2 CEM data from about the same time period was also obtained and summarized below in Table1. The amount of sulphur in the coal is directly related to the SO_2 emission rate.

Table 1: Continuous SO_2 Emission Monitor for Coal Boilers

Value Description	EQUI 1 (Boiler 1A) and EQUI 2 (Boiler 2A) - common stack		EQUI 3 (Boiler 3A)	
	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu
January 2021 Average	64.5	0.30	90.8	0.37
February 2021 Average	119.76	0.55	142.4	0.57
March 2021 Average	0	0	89.0	0.37
April 2021 Average	61.4	0.36	72.24	0.29

Projected emissions will be dependent on the long-term plan HPUC is currently formulating over the course of the next several years. No additional insight on that can be provided at this time.

Four Factor Analysis

Retrofit Factor

The USEPA requested additional information to support the use of the 30 percent retrofit factor was used for installation of selective catalytic reduction technology. The factor was obtained from EPA/452/B-02-001 - EPA Air Pollution Control Cost Manual, Chapter 2 Section 4, page 2-29 states 30% for a retrofit factor. The Air Pollution Control Cost Estimation Spreadsheet for SCR, USEPA June 2019, states that the retrofit should be between 0.8 and 1.5 based on the level of difficulty. The USEPA spreadsheet states that a retrofit factor of 1 is for average difficulty. Based on the space constraints and limited construction season due to the climate in Hibbing, Minnesota a cost percentage of 30 percent was used which is the same as a factor of 1.3.

Boiler 1A (EQUI 1) and Boiler 2A (EQUI 2)

Boilers 1A and 2A vent to a common stack and are identical units. The analysis as completed for Boiler 1A would be identical to an analysis completed for Boiler 2A.

Permitted Allowable Facility-Wide SO_2 Emission Rate when Burning Coal

The FLM referenced a permit condition that limits SO_2 to less than or equal to 4.0 pounds per million British Thermal Units per hour (MMBtu/hr) heat input when burning coal (permit condition 5.6.10 – Boiler 1A, permit condition 5.7.11– Boiler 2A, permit condition 5.8.11– Boiler 3A; rule citation Minn. R. 7011.0510, subpart 1). The permit condition in question is from a Minnesota regulation and is the limit for any solid fuel. This regulatory limit will remain in the permit regardless of if a new lower lb/MMBtu SO_2 limit is established. It is not the limit that restricts the SO_2 emissions from the solid fuel boilers at HPUC. The MPCA includes all regulatory restrictions in operating permits not just the most restrictive limit.

The July 28, 2020 Four Factor analysis listed the 4 lbs/MMBtu SO_2 limit but failed to also list the more restrictive SO_2 limits for the coal fired boilers which is 0.90 lbs/MMBtu.

The permit limit that restricts SO_2 from the boilers:

- Boiler 1A Permit Condition 5.6.8 - limits SO_2 to equal or less than 194.40 lbs/hour on a 1-hour average. At the rated capacity of the boiler (216 MMBtu/hr) this would equate to 0.90 lbs/MMBtu which is more restrictive than the allowed SO_2 emission rate from Minn. R. 7011.0510, subpart 1.

- Boiler 2A Permit Condition 5.7.9 - limits SO_2 to equal or less than 194.40 lbs/hour on a 1-hour average. At the rated capacity of the boiler (216 MMBtu/hr) this would equate to 0.90 lbs/MMBtu which is more restrictive than the allowed SO_2 emission rate from Minn. R. 7011.0510, subpart 1.

- Boiler 3A Permit Condition 5.8.9 - limits SO_2 to equal or less than 223.20 lbs/hour on a 1-hour average. At the rated capacity of the boiler (248 MMBtu/hr) this would equate to 0.90 lbs/MMBtu which is more restrictive than the allowed SO_2 emission rate from Minn. R. 7011.0510, subpart 1.Boiler 3A also has a permit limit for SO_2 that equates to 0.90 lbs/MMBtu.

There is no need to impose additional restrictions on the SO_2 emission rate from the boilers. The permit contains a much more restrictive limits than the one listed in the July 28, 2020 Four Factor Analysis which was cited by the FLM.

Inflation Rate and Cost to Install

The inflation rate is accelerating faster than expected as the economy recovers from the COVID Pandemic.

> "Inflation in April accelerated at its fastest pace in more than 12 years as the U.S. economic recovery kicked into gear and energy prices jumped higher" (CNBC published, MAY 12, 2021).

This means the inflation rate used in the July 2020 report are no longer valid and need to be adjusted upwards. The cost calculations are based on dollars at a point in time. Those dollars are then adjusted to reflect the current year cost. Table 2 presents the dollars from the cost control calculations for SO_2 contained in the July 28, 2020 Four Factor Analysis adjusted for 2021 dollars.

Table 2: SO_2 Emission Control Cost Totals Adjusted for Inflation

Description	EQUI 1 (Boiler 1A) – Common Stack with EQUI 2 (Boiler 2A)		EQUI 3 (Boiler 3A)	
	Wet	Dry	Wet	Dry
Subtotal Cost 2001 $	$180,492,000	$196,690,000	$216,996,000	$236,470,000
Subtotal Adjusted for 2020 $	$265,738,372	$289,586,687	$319,483,211	$348,154,781
Cost of Reduction 2020 $/Ton	$2,711,339	$3,323,998	$3,218,974	$3,946,438[d]
Subtotal Adjusted for 2021 $[a]	$285,177,360	$310,770,200	$342,853,680	$373,622,600
Cost of Reduction 2021 $/Ton	$2,909,676	$3,567,151	$3,454,445	$4,235,124

[a] *The inflation rate in the United States between 2001 and today is 47.23%, (U.S. Bureau of Labor Statistics), https://www.bls.gov/data/inflation_calculator.htm, July 2020. The inflation rate between 2001 to April 2021 is 58%. April 2021 was the most recent data available on the U.S. Bureau of Labor Statistics.*

Table 3 presents the dollars from the cost control calculations for NO_x contained in the July 28, 2020 Four Factor Analysis adjusted for 2021 dollars.

Table 3: NOx Emission Control Cost adjusted for Inflation

Description	EQUI 1 (Boiler 1A) – Common Stack with EQUI 2 (Boiler 2A)		EQUI 3 (Boiler 3A)		EQUI 7 (Boiler 4)
	SNCR	SCR	SNCR	SCR	SCR
Subtotal Cost 1999 $[a]	$521,800	$3,920,400	$567,100	$4,501,200	$1,759,500
Subtotal Adjusted for 2020 $[a]	$818,756	$6,151,500	$889,837	$7,062,833	$2,760,831
Cost of Reduction 2020 $/Ton	$18,966	$67,054	$15,443	$57,684	$67,800
Subtotal Adjusted for 2021 $[a]	$850,534	$6,390,252	$924,373	$7,336,956	$2,867,985
Cost of Reduction 2021 $/Ton	$19,702	$69,656	$16,043	$59,923	70,432

[a] *The inflation rate in the United States between 1999 and today is 56.91%, (U.S. Bureau of Labor Statistics), https://www.bls.gov/data/inflation_calculator.htm, July 2020. The inflation rate between 1999 to April 2021 is 63%. April 2021 was the most recent data available on the U.S. Bureau of Labor Statistics.*

Summary and Next Steps

HPUC is not in a position to commit its future operation or fuel mix at this time as it is re-embarking on pilot season of burning biomass fuel for the 2021/2022 heating season for the purposes of gathering more data and optimizing sustainability operations for future growth. HPU believes its future operating plan is one that will promote self-reliance, operational flexibility, sustainability, and overall push to lower their environmental impact. As HPU begins its pilot year of operations with biomass we look forward to working with the MPCA to ensure best in class work towards a more sustainable future with locally sourced, locally managed, sustainable thermal operations and associated permits.

Based on the additional review of information and response to questions, HPUC feels the retrofit factor used is correct and that the SO_2 limits on the boilers are close to the actual emissions with some room to manage the variability of a natural product like coal.

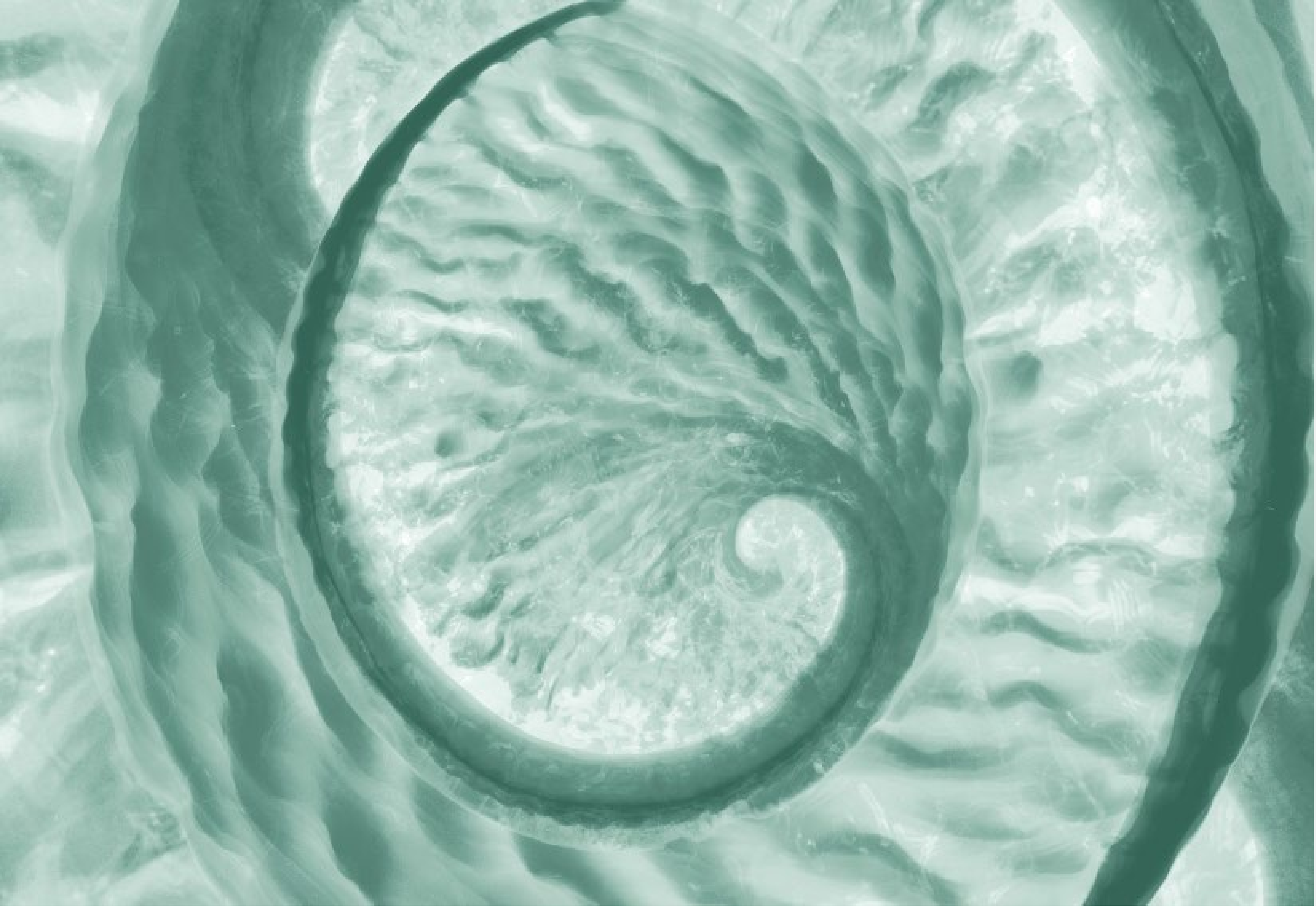
The cost associated with control have increased since the July 2020 analysis and the costs were updated using recent inflation rate information. The cost of control has become even more prohibitive with inflation. Even so, HPU looks forward to exploring all options for providing and controlling SO2 in a way that incrementally builds towards HPU's goals of energy self-reliance, flexibility, and restorative growth for the Northern Minnesota Economy and Environment.

I look forward to addressing any questions you have over the months and years ahead.

Best Regards and Thanks,

Luke J. Peterson

Luke J. Peterson
General Manager
Hibbing Public Utilities



Four Factor Analysis

Hibbing Public Utilities Commission

Hibbing, Minnesota

28 July 2020

Project No.: 0560921

The business of sustainability

ERM

Document details	This document documents the four factor analysis of the sulfur dioxide (SO2) emissions from EQUI 1 and EQUI 3, as well as nitrogen oxide (NOx) emissions from EQUI 1, EQUI 3, and EQUI 7. Hibbing Public Utilities Commission is located in Hibbing, Minnesota.
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Acronyms and Abbreviations

Name	Description
°F	degrees Fahrenheit
BACT	Best Available Control Technology
CEM	continuous emission monitor
CFR	Code of Federal Regulations
CO	carbon monoxide
DSI	dry sorbent injection
ESP	electrostatic precipitator
FGD	Flue Gas Desulfurization
HPUC	Hibbing Public Utilities Commission
hr	hour
ICAC	Institute of Clean Air Companies
kW	kilowatts
LAER	Lowest Achievable Emission Rate
lb	pounds
LNB	Low NO_x Burner
LSD	Lime Spray Dryer
LSFO	Limestone Forced Oxidation
MMBtu	million British thermal units
MPCA	Minnesota Pollution Control Agency
MW	megawatts
NO_x	nitrogen oxide
NSR	New Source Review
O&M	operation and maintenance
OFA	over-fire air
RBLC	RACT/BACT/LAER Clearinghouse
SCR	Selective Catalytic Reduction
SDA	spray dyer absorber
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
tpy	tons per year
USEPA	U.S. Environmental Protection Agency
WFGD	Wet Flue Gas Desulfurization

1. INTRODUCTION

Under 40 Code of Federal Regulations Part 52 (40 CFR 52) Subpart P Section 51.308, states are required to develop a long-term strategy for regional haze. Each State must submit a long-term strategy that addresses regional haze visibility impairment for each mandatory Class I Federal area within the State and for those areas located outside the State that may be affected by emissions from within the State. The long-term strategy must include the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress toward achieving natural visibility conditions in the affected Class I Federal area.

40 CFR 52 Subpart P, Section 51.308(f)(2)(i) requires the State to evaluate and determine the emission reduction measures that are necessary to make reasonable progress by considering four factors:

1. Cost of compliance,
2. Time necessary for compliance,
3. Energy and non-air quality environmental impacts of compliance, and
4. Remaining useful life of any potentially affected emission unit.

The State Implementation Plan must include a description of the criteria it used to determine which sources or groups of sources it evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy. In considering the time necessary for compliance, if the State concludes that a control measure cannot reasonably be installed and become operational until after the end of the implementation period, the State may not consider this fact in determining whether the measure is necessary to make reasonable progress. Revisions to the Minnesota Regional Haze Implementation Plan are due to the U.S. Environmental Protection Agency (USEPA) by July 31, 2021, and the implementation period is 10 years to demonstrate progress toward attaining the visibility goals.

In a letter dated February 14, 2020, the Minnesota Pollution Control Agency (MPCA) requested that the Hibbing Public Utilities Commission (HPUC) conduct a four-factor analysis of the nitrogen oxide (NO_x) and sulfur dioxide (SO_2) emissions from Boiler 1A (EQUI 1 / EU 001), Boiler 3A (EQUI 3 / EU 003) and Wood-Fired Boiler EQUI 7 (EU007). Boiler 2A (EQUI 2 / EU002) has a common stack with Boiler 1A but was not part of the Four Factor Analysis request. In a telephone conversation with the MPCA Regional Haze contact, Mr. Hassan Bouchareb, ERM was informed that Boiler 2A was not in the request because the base year triggering the review was 2016, and Boiler 2A did not operate in 2016.

The Class 1 areas in proximity to HPUC are Boundary Waters Canoe Area Wilderness and Voyageurs National Park. The center of the Boundary Waters Canoe Area Wilderness is approximately 75 miles from HPUC, and its closest point is approximately 43 miles from HPUC. The center of Voyageurs National Park is approximately 73 miles from HPUC, and its closest point is approximately 64 miles from HPUC. A site location map showing HPUC relative to the two Class 1 areas is provided in Appendix A.

This report documents the four-factor analysis for controlling SO_2 and NO_x from Boiler 1A and Boiler 3A as well as controlling NO_x emissions from the Wood Fired Boiler (EQUI 7) at HPUC. For the rest of this analysis, references to Boiler 1A and 3A will be based on the MPCA air permit identification of these sources, which are EQUI 1 and EQUI 3, respectively. A brief description of HPUC and boiler actual emissions is provided in Section 2 of this report. Section 3 of this report includes the four-factor analysis. The following information is included in Section 3.

- Technically feasible control technology available for NO_x reductions and the cost of control.
- The time schedule necessary for implementing a control strategy is described in general terms accounting for project approval, engineering design, bidding, procurement/contracting, construction, and commissioning.
- The non-air quality impacts of compliance are identified and costs estimated to the extent possible. These include truck traffic, electrical use, solid waste generation, and water use.
- The remaining useful life of the boilers is discussed in terms of the maintenance of the unit and projects for the remaining life of the unit before a major overhaul or replacement is due.
- A general discussion of cost effectiveness is included in the summary section. This discussion is based on a review of published information on the reasonableness cost per ton of SO_2 and NO_x removed as related to visibility improvement.

2. PLANT DESCRIPTION

The HPUC operates a co-generation facility for the city of Hibbing. The facility has the ability to generate electricity and steam. Currently, the facility is not generating electricity and solely providing steam to their steam distribution system for space heating and industrial purposes to nearby businesses, schools, and residences. The HPUC is considered a district heating plant and is located in downtown Hibbing, in close proximity to its steam customers.

HPUC operates in accordance with a federal 40 CFR Part 70 Permit number 13700027-101, issued on May 8, 2018. The combustion emission units at the facility consist of three coal-fired boilers EQUI 1, EQUI 2, EQUI 3, and wood-fired boiler EQUI 7. Attached to the steam distribution system, but not at the main HPUC facility, are two small natural gas fired boilers capable of serving the Hibbing High School. The high school boilers have not been operated in years.

EQUI 7 was permitted in 2005 and was required to demonstrate Best Available Control Technology (BACT) and compliance with the National Ambient Air Quality Standards in place at that time (Permit No. 13700027-003). A gas burner was permitted (Permit No. 13700027-009) and installed in 2015 to assist in stabilizing combustion to lower carbon monoxide (CO) emissions. The natural gas burners were needed to counteract the fluctuation of the moisture content of the wood fuel being received, which was causing swings that led to CO emissions exceeding permit limits too frequently.

EQUI 7 uses selective non-catalytic reduction (SNCR) for NO_x control and a multi-cyclone followed by an electrostatic precipitator (ESP) for particulate matter control. The boiler is also equipped with an opacity monitor, NO_x monitor, and CO monitor. The boiler design includes over-fire air (OFA), which will reduce the formation of NO_x but was not specifically included for NO_x control and is not listed in the air permit as control for NO_x. Additional information on the existing OFA system is in subsequent paragraphs.

HPUC no longer holds a power purchase agreement with Xcel Energy. Currently, HPUC has no intention of generating electricity. Going forward, HPUC will operate in a similar manner as how the facility was operated in the past year, which is not operating the wood boiler, limiting coal to one trainload a season (14,000 tons), and burning natural gas as needed to satisfy district steam loads.

2.1 SO_2 and NO_x Emissions

A summary of recent continuous emission monitor information is listed in Table 1.

Table 1: Continuous Emission Monitor

Value Description	EQUI 1 and EQUI 2 SO_2 (lb/MMBtu)	EQUI 3 SO_2 (lb/MMBtu)	EQUI 7 NO_x (lb/MMBtu)
Minimum	0	0	0
Maximum	0.47 [a]	0.52 [a]	0.155 [b]
Range [c]	0.47	0.52	0.155
Average	0.10	0.17	0.0.03

Abbreviations: lb = pounds; MMBtu = million British thermal units

[a] *Permit limit for each coal-fired boiler (EQUI 1, EQUI 2, and EQUI 3) is 4.0 lbs/MMBtu when combusting coal.*

[b] *Permit limit for EQUI 7 is 0.15 lb/MMBtu based on a 30-day average. The value shown for EQUI 7 in this table is one instance in time, not a 30-day average.*

[c] *Range is the difference between the highest (maximum) and the lowest (minimum) within a set of numbers.*

The potential emissions of SO_2 from EQUI 1 and EQUI 2 are 194 pounds per hour (lb/hr) and 851 tons per year (tpy) each. The potential emissions of SO_2 from EQUI 3 are 223 lb/hr and 978 tpy.

The potential emissions of NO_x from EQUI 1 and EQUI 2 are 140 lb/hr and 612 tpy each. The potential emissions of NO_x from EQUI 3 are 160 lb/hr and 703 tpy. The potential emissions of NO_x for EQUI 7 while burning wood are 34.5 lb/hr and 151.11 tpy.

2.2 Historical SO_2 and NO_x Emissions

Historical emissions were taken from the actual air emission reports HPUC submitted to the MPCA for last 4 years. EQUI 2 was not requested to be included in the analysis by the MPCA, but the boiler shares a common stack with EQUI 1 and so was included for informational purposes. The actual emission rates are based on the continuous emission monitors and are the values reported to the MPCA for the annual actual emission reports.

The actual annual SO_2 emissions have decreased each year from 2016 to 2019. Table 2 provides the actual annual SO_2 emission rates from 2016 to 2019 for each of the coal boilers. The wood boiler EQUI 7 is not included because the amount of sulfur in wood is minimal, which results in minor emissions of SO_2 from the combustion reaction.

Table 2: Historical SO_2 Emissions

Year	EQUI 1 (tpy)	EQUI 2 (tpy)	EQUI 3 (tpy)
2016	167.5	37.3	168.3
2017	181.7	1.2	158.0
2018	83.1	2.15E-14	78.6
2019	3.3	2.15E-14	36.2
Average	108.90	9.63	110.28

The actual annual NO_x emissions have decreased each year from 2016 to 2019. Table 3 provides the actual annual NO_x emission rates from 2016 to 2019 as reported to the MPCA for the three coal boilers and the wood-fired boiler at HPUC.

Table 3: Historical NO_x Emissions

Year	EQUI 1 (tpy)	EQUI 2 (tpy)	EQUI 3 (tpy)	EQUI 7 (tpy)
2016	157.8	39	193.6	87.0
2017	118.9	1.1	167.1	86.8
2018	111.8	1.9E-14	133.3	31.9
2019	43.2	1.9E-14	82.2	15.2
Average	107.93	10.03	144.05	55.23

3. FOUR-FACTOR ANALYSIS

The following is the four-factor analysis. The following subsections present information on the cost of SO_2 and NO_x control for EQUI 1 and EQUI 3 and supplemental NO_x control for EQUI 7. Boiler EQUI 7 already has NO_x control, so the analysis is based on the incremental reduction of changing the control system already in place. The analysis includes the time necessary to implement controls, the energy and non-air quality environmental impacts of implementing controls, and the remaining useful life of the boilers.

3.1 SO_2 Control Technology

A literature review of available control technology for coal fired boilers was conducted and two commercially available Flue Gas Desulfurization (FGD) technology options are available for removing SO_2 produced by coal-fired boilers. The two technologies identified as commercially available that could be applied to EQUI 1 and EQUI 2 are:

1. Limestone Forced Oxidation (LSFO) Scrubber, and
2. Lime Spray Dryer (LSD) Scrubber.

LSFO – LSFO is a wet FGD technology. In a wet system the exhaust gas is mixed with a liquid alkaline sorbent (typically limestone). The mixing is achieved by forcing the exhaust stream through a pool off liquid slurry or by spraying the exhaust with a liquid. This technology is commonly simply referred to as wet scrubbing. According to vendor information, a new wet scrubber can routinely achieve SO_2 removal efficiencies of 95% (Institute of Clean Air Companies [ICAC] Acid Gas/SO_2 Controls), https://www.icac.com/page/Acid_Gas_SO2_Control.

LSD – LSD is a semi-dry FGD technology that uses a spray dyer absorber. In dry FGD systems, the exhaust stream is brought into contact with the alkaline sorbent in a semi-dry state through use of a spray dryer. The removal efficiency is dependent on the amount of sulfur in the coal. This technology is often referred to as dry scrubbing or dry sorbent injection. A fabric filter/baghouse is required downstream of the scrubber to collect the sorbent used to absorb the SO_2. This technology is commonly referred to as a spray dryer.

In addition to the literature review, a search of the USEPA RACT/BACT/LAER Clearinghouse (RBLC) database for Process Type 12.110 Industrial Boiler firing coal and Process Type 11.110 Utility and Large Industrial Boiler firing coal for January 1, 2010 through June 30, 2020 was conducted on June 30, 2020 to identify what SO_2 control strategies are in place and what emission levels represent the BACT. BACT limits are emission rates and are determined on a case-by-case basis. The BACT emission rates are used in this report for comparison purposes only and do not represent an applicable standard.

Eleven plants were listed in the RBLC database; all but one had add-on SO_2 control listed. The only facility with a coal boiler to not list SO_2 control, only an SO_2 limit, was Miller Brewing Company in Ohio. A summary of the RBLC entries for boilers firing coal is attached as Appendix B, the entries specific to SO_2 are in table B-1.

Of the FGD systems installed, 85% are wet systems and 12% are spray dryers. Wet scrubbers can achieve the highest removal efficiencies at greater than 90%, whereas dry scrubbers typically achieve less than 80% (USEPA Fact Sheet).

3.2 NO_x Control Technology

In August 2010 the USEPA published "Documentation for Integrated Planning Model Base Case" that included NO_x emission control information prepared by engineering firm Sargent and Lundy (USEPA 2020) https://www.epa.gov/airmarkets/documentation-integrated-planning-model-ipm-base-case-v410. Sargent and Lundy performed a complete bottom-up engineering reassessment of the cost and performance assumptions NO_x emission controls for large utility boilers.

Available control options identified are:

- Low NO_x Burner (LNB) without OFA,
- LNB with OFA,
- OFA,
- Selective Catalytic Reduction (SCR), and
- SNCR.

3.2.1 Coal-Fired Boilers EQUI 1 and EQUI 3 NO_x Control Technology

The coal-fired boilers at HPUC do not employ any add on control technologies for NO_x reduction. None of the coal-fired boilers have been subject to federal New Source Review (NSR) permitting, which would have required review and installation of BACT.

A search of the RBLC was conducted on June 30, 2020 to identify what NO_x control strategies are in place for coal-fired/natural gas boilers around the country and what emission levels represent the BACT. BACT limits are emission rates and are determined on a case-by-case basis. The BACT emission rates are used in this report for comparison purposes only and do not represent an applicable standard.

An RBLC search for Process Type 12.110 Industrial Boiler firing coal and Process Type 11.110 Utility and Large Industrial Boiler firing coal for January 1, 2010 through June 30, 2020 found 15 entries, which were all for NO_x. Of the 15 entries found, 5 were noted as having SNCR and 3 indicated SCR. A summary of the RBLC entries for boilers firing coal is attached as Appendix B; entries specific to NO_x are in table B-2.

LNB – LNBs control the fuel and air mixture in order to create larger and more branched flames. This reduces the peak flame temperature and in turn reduces NO_x formation.

OFA Systems – Additional NO_x reduction can be achieved by integrating staged combustion (OFA) into the overall system. OFA can be used by itself but is most often used in conjunction with other NO_x reduction systems.

SCR – SCR uses a liquid reducing agent in combination with a catalyst to convert NO_x into nitrogen and water. The reducing agent most commonly used is ammonia.

SNCR – Like the SCR system, SNCR also converts NO_x into nitrogen and water. However, no catalyst is used; instead, the reagent is injected at a high temperature.

3.2.1.1 LNB

EQUI 1 and EQUI 3 are stoker boilers, which means a solid fuel (in this case coal) is mechanically fed into the combustion chamber and the fuel sits on top of a grate during combustion. LNB is not a fuel delivery option for this type of a solid fuel. LNB is not technically feasible and was eliminated from additional discussion for combustion of a solid fuel.

3.2.1.2 OFA

An OFA system is a design feature of boilers to ensure adequate air to promote combustion efficiency. The coal-fired boilers were designed with OFA for proper combustion efficiency. Since OFA is an inherent part of the boiler design, it was not specifically identified as a pollution control technology.

3.2.1.3 SNCR

SNCR reduces the formation of NO_x by injecting an ammonia type reactant into the furnace at a properly determined location. SNCR is used on a wide-range of industrial boilers. SNCR can also accommodate seasonal or year-round boiler operation. Reported SNCR reduction efficiencies vary depending on temperature, residence time, reducing reagent, reagent injection rate, uncontrolled NO_x level, distribution of the reagent in the flue gas, and CO and oxygen concentrations. USEPA “Air Pollution Control Technology Fact Sheet” EPA-452/F-03-031 states that achievable NO_x reduction levels range from 30 to 50% (USEPA 2002). A copy of the USEPA fact sheet is provided in Appendix C.

SCR is the highest-performing control option currently available. According to the USEPA “Air Pollution Control Technology Fact Sheet” for SCR (EPA-452/F-03-032), SCR is capable of NO_x reduction efficiencies in the range of 70 to 90% (ICAC 2000). A copy of the USEPA fact sheet is provided in Appendix D.

3.2.2 Wood-fired Boiler NO_x Control Technology

A BACT analysis was completed for EQUI 7 when it was initially permitted in 2005. That analysis indicated that SNCR and a NO_x emission rate of 0.15 lb per million British thermal units (MMBtu) was BACT. An excerpt from the technical support document that was attached to the operating permit is provided below.

MPCA Technical Support Document, Permit Action Number: 13700028-005 Page 17 of 64, 7/11/2005

> *Nitrogen oxide controls from the RBLC database records indicate a wide range of technologies as BACT, including no control, combustion control, SNCR and SCR. Again the most stringent control, SCR appears in the permit for RBLC record OH-0269, however that facility has not been constructed and the permit has expired. BACT emission rates range from 0.15 to 0.40 pounds per million Btu, excluding OH-0269 which has not been constructed. The lowest BACT emission rate for a constructed and operating facility is 0.15 lbs/MMBtu from the District Energy St. Paul facility, which employs SNCR technology.*

In August 2010, the USEPA published “Documentation for Integrated Planning Model Base Case,” which included NO_x emission control information prepared by engineering firm Sargent and Lundy (USEPA 2020) https://www.epa.gov/airmarkets/documentation-integrated-planning-model-ipm-base-case-v410. Sargent and Lundy performed a complete bottom-up engineering reassessment of the cost and performance assumptions NO_X emission controls for large utility coal fired boilers. The study is not directly relatable to smaller wood boilers, but the identified control technologies available for NO_x control would be the same.

Available control options identified are:

- LNB without OFA,
- LNB with OFA,
- OFA,
- SCR, and
- SNCR.

A new search of the RBLC was conducted on June 30, 2020, to identify what NO_x control strategies are in place for wood-fired/natural gas boilers around the country and what emission levels represent the BACT. BACT limits are emission rates and are determined on a case-by-case basis. The BACT emission rates are used in this report for comparison purposes only and do not represent an applicable standard.

An RBLC search for Process Type 12.120 Industrial Boiler Firing Biomass (includes wood and wood waste) and Process Type 11.120 Utility and Large Industrial Boiler firing Biomass (includes wood and wood waste) for January 1, 2010 through June 30, 2020 found 19 entries. Of the 19 entries found, 10 were noted as having SNCR and 7 indicated SCR. Of the seven entries that indicated SCR was being used for control, only one—Berlin Station LLC, which has a rated capacity of 1,013 MMBtu/hr (over four times larger than EQUI 7)—has been built and is operating. The Berlin Station boiler was the only boiler able to be confirmed to have been built with SCR. The boiler was required to comply with the Lowest Achievable Emission Rate (LAER) requirements. The boiler is noted as having SCR much larger in capacity (464 to 1,200 MMBtu/hr) than EQUI 7 (230 MMBtu/hr). The other entries found were listed as having LNBs. Some boilers also indicated OFA as part of the boiler design. A summary of the RBLC entries is attached as Appendix B, with specific entries for wood-fired boilers listed in table B-3.

LNB – LNBs control the fuel and air mixture in order to create larger and more branched flames. This reduces the peak flame temperature and in turn reduces NO_x formation.

OFA – Additional NO_x reduction can be achieved by integrating staged combustion (OFA) into the overall system. OFA can be used by itself but is most often used in conjunction with other NO_x reduction systems.

SCR – SCR uses a liquid reducing agent in combination with a catalyst to convert NO_x into nitrogen and water. The reducing agent most commonly used is ammonia.

SNCR – Like the SCR system, SNCR also converts NO_x into nitrogen and water. However, no catalyst is used; instead the reagent is injected at a high temperature.

3.2.2.1 LNB

The wood-fired boiler is a stoker boiler which means a solid fuel (in this case wood) is mechanically fed into the combustion chamber and the fuel sits on top of a grate during combustion. The wood that is added is in chip form which is around 3 inches in size. LNB is not a fuel delivery option for this type of a solid fuel. LNB is not technically feasible and was eliminated from additional discussion for wood combustion.

The natural gas burners, installed in 2015 to stabilize combustion, are LNB. Combustion stabilization is necessary due to the variability in the moisture content of the wood, which was causing large swings in CO emissions. Natural gas is not the primary fuel, and as such not the focus of this analysis.

3.2.2.2 OFA

An OFA system is a design feature of boilers to ensure adequate air to promote combustion efficiency. In boiler EQUI 7, air for combustion is supplied from two separate sources: undergate air and OFA. The undergate air supplies 60% of the required combustion air, while the OFA makes up the remaining 40%. The OFA system provides combustion air to a serious of fixed nozzles that penetrate the furnace front and rear walls. There are three elevations of nozzles on the front wall and four elevations of nozzles on the rear wall. The nozzles are optimized to inject air above the grate into a zone where suspension burning takes place. Different nozzle elevations are used to optimize combustion while minimizing emissions from combustion. Both systems are required to be operating when wood is being combusted.

A portion of the operator's manual provided by Foster Wheeler, which provides a detailed description of the OFA system, is provided in Appendix E. The air permit for EQUI 7 does not list OFA as a pollution control device because it is considered a factor of boiler design, not an add-on control system.

Compliance with 40 CFR 63 Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters—more commonly referred to as "Boiler MACT"—requires EQUI 7 to be tuned annually. The tune-ups focus on boiler efficiency, which would have an impact on improving air emissions.

3.2.2.3 SNCR

EQUI 7 has an SNCR system for NO_x reduction and, as such, no additional discussion on this technology is provided since it is already in use.

3.2.2.4 SCR

SCR is the highest-performing control option currently available. According to the USEPA "Air Pollution Control Technology Fact Sheet" for SCR (EPA-452/F-03-032), SCR is capable of NO_x reduction efficiencies in the range of 70 to 90% (ICAC 2000). A copy of the USEPA fact sheet is provided in Appendix D. Higher reductions are noted by the USEPA as possible but generally not cost-effective. SCR makes use of a catalyst with ammonia injection. The catalyst improves the efficiency of the chemical reduction of NO_x by ammonia. The SCR is designed to evenly distribute the flow of NO_x across a catalyst surface, and provide thorough mixing of the injected ammonia to facilitate reduction and thus removal of NO_x. The catalyst requires gas at a sufficient temperature for the chemical reaction to occur. The boiler exhaust gas also requires particulate removal prior to the SCR to prevent fouling of the catalyst.

The potential use of SCR for control of NO_x from the EQUI 7 was evaluated as BACT when the boiler was originally permitted in 2005. The BACT analysis completed as part of the 2005 permit action indicated that SCR was an infeasible NO_x control option for a wood-fired boiler. The reason the technology was considered infeasible was because of the higher levels of silicates and other constituents found in biomass fuels, which lead to rapid fouling of the catalyst bed, greatly reducing the effectiveness of the SCR system and leading to significant downtime and expense in replacing the catalyst.

The RBLC did note some wood-fired boilers that have been permitted with SCR. The boilers listed as using SCR for NO_x control are all much larger than EQUI 7 and, most likely, operate at a higher capacity factor. Two of the entries that cited SCR noted the basis for the technology as a requirement to permit at LAER. EQUI 7's primary function at HPUC is to serve the district heating system. HPUC does have some demand for steam in the summer but the majority of the steam production is during the heating season. The HPUC steam customer base continues to decrease as some former entities are relocating outside of the service area or transitioning to their own on-site steam production/heat production.

3.3 Cost Summary

3.3.1 Coal-Fired Boilers EQUI 1A and 3A

3.3.1.1 SO_2 Control Costs

The costs for SO_2 control are based on USEPA published information taken from the USEPA "Air Pollution Control Technology Fact Sheet" EPA-452/F-03-034 for FGD, a copy of which is in Appendix F. The cost information from the fact sheet is contained in table 1b – Summary of Cost Information in $/kilowatts (kW) (2001 Dollars). The table entry for Industrial Coal Boilers was used for EQUI 1 and EQUI 3. Where cost values have been provided as ranges, the average of the range has been used for estimating purposes.

If a spray dryer technology is used a fabric filter will need to be added downstream of the scrubber to remove the sorbent that was injected in to the exhaust stream. The particulate collector is designed and operated as an integral part of the removal process as the solids continue to react with SO_2,

The level of SO_2 reductions are based on the actual annual emissions over the past 4 years. Because the facility is no longer producing electricity and district heating customers continue to decline, the operation of the boilers has trended downward. HPUC expects that the trend for decreased operation will become the normal operating mode going forward. As stated earlier, HPUC is only expecting to purchase one unit train of coal for winter operation. The results of the cost estimating for both wet and spray dry technology are shown in Table 4.

Table 4: EQUI 1 and EQUI 3 SO_2 Control Cost Estimate Summary

Parameter	EQUI 1 (17.8 MW, 17,800 kW)		EQUI 3 (21.4 MW, 21,400 kW)	
	Wet	Spray Dry	Wet	Spray Dry
Capital Cost (875 $/kW for wet and 675 $/KW for spray dry)	$15,575,000	$12,015,000	$18,725,000	$14,445,000
O&M Cost (14 $/kW for wet and 155 $/KW for spray dry)	$249,200	$275,900	$299,600	$3,317,000
Annual Cost (125 $/kW for wet and 275 $/KW for spray dry)	$2,225,000	$4,895,000	$2,675,000	$5,885,000
Subtotal (2001 $)	$18,049,200	$19,669,000	$21,699,600	$23,647,000
Subtotal Adjusted for 2020 $ [a]	$26,573,837	$28,958,669	$31,948,321	$34,815,478
Emission Reduction Percent	90%	80%	90%	80%
Emission Reduction [b] (tpy)	98.01	87.12	99.25	88.22
Cost of Emission Reduction ($/ton) [c]	**$271,134**	**$332,399**[d]	**$321,897**	**$394,644**[d]

Abbreviations: MW = megawatts; O&M = operation and maintenance

[a] *The inflation rate in the United States between 2001 and today is 47.23%, (U.S. Bureau of Labor Statistics), https://www.bls.gov/data/inflation_calculator.htm, July 2020.*

[b] *Emission reduction is based on a 4-year average of actual emissions reported from 2016–2019. Emissions of 108.90 tons of SO_2 are from EQUI 1 and 110.28 tons of SO_2 are from EQUI 3.*

[c] *Cost of emission reduction is rounded to the nearest whole dollar.*

[d] *Cost of emission reduction does not include the addition of a fabric filter down stream of the spray dryer.*

3.3.1.2 NO_x Control SNCR Cost

Table 5 summarizes the cost of retrofitting EQUI 1 and EQUI 3 with an SNCR NO_x control system. Costs are based on the USEPA “Air Pollution Control Technology Fact Sheet” for SNCR, EPA-452/F-03-031, page 2, a copy of which is in Appendix C. Information is in $/MMBtu/hr and $/megawatts (MW) (1999 Dollars). The excerpt from the fact sheet concerning SNCR costs for industrial boilers greater than 100 MMBtu/hr is presented below.

1. Capital Cost: 900 to 2,500 $/MMBtu/hr (9,000 to 25,000 $/MW)
2. Operation and Maintenance (O&M) Cost: 100 to 500 $/MMBtu/hr (1,000 to 5,000 $/MW)
3. Annualized Cost: 300 to 1,000 $/MMBtu/hr (3,000 to 10,000 $/MW)

EQUI 1 is 17.8 MW and EQUI 3 is 21.4 MW. SNCR is applicable to boilers operated full time as well as boilers only operated on a seasonal basis.

Table 5: EQUI 1 and EQUI 3 SNCR NO_x Control Cost Estimate Summary

Parameter	EQUI 1 (17.8 MW/216 MMBtu/hr)	EQUI 3 (21.4 MW/248 MMBtu/hr)
Capital Cost (17,000 $/MW)	$302,600	$363,800
O&M Cost (3,000 $/MW)	$103,500	$64,200
Annual Cost (6,500 $/MW)	$115,700	$139,100
SNCR Subtotal (1999 $)	$521,800	$567,100
SNCR Subtotal Adjusted for 2020 $ [a]	$818,756	$889,837
Emission Reduction Percent	40%	40%
Emission Reduction [b] (tpy)	43.17	57.62
Cost of Emission Reduction [c] ($/ton)	$18,966	$15,443

[a] *The inflation rate in the United States between 1999 and today is 56.91%, (U.S. Bureau of Labor Statistics, https://www.bls.gov/data/inflation_calculator.htm, July 2020.*

[b] *Emission reduction is based on a 4-year actual average of 2016–2019 emissions of 107.93 tons of NO_x from EQUI 1 and 144.05 tons of NO_x from EQUI 3.*

[c] *Cost of emission reduction is rounded to the nearest whole dollar.*

The cost to retrofit EQUI 1 and EQUI 3 with SNCR would be about $19,000 and $15,500 per ton of NO_x removed. Since the dissolution of the Xcel Power Purchase Agreement and the decline in steam customers, HPUC has seen a reduction in use of all the boilers on site, as evident in the summary of historical NO_x actual emissions contained in Table 3.

3.3.1.3 NO_x Control SCR Cost

The costs for NO_x control are based on USEPA published information taken from the USEPA “Air Pollution Control Technology Fact Sheet” for SCR, EPA-452/F-03-032, a copy of which is in Appendix D. The cost information from the fact sheet is contained in table 1a – Summary of Cost Information in $/MMBtu/hr (1999 Dollars). The table entry for Industrial Coal Boilers was used for EQUI 1 and EQUI 3. Where cost values have been provided as ranges, the average of the range has been used for estimating purposes. The control efficiency of SCR is based on an 85% capacity factor and annual control of NO_x. Table 6 summarizes the costs associated with retrofitting EQUI 1 and EQUI 3 with SCR for NO_x Control.

Table 6: EQUI 1 and EQUI 3 SCR NO_x Control Cost Estimate Summary

Parameter	EQUI 1 (216 MMBtu/hr)	EQUI 3 (248 MMBtu/hr)
Capital Cost (12,500 $/MMBtu)	$2,700,000	$3,100,000
30% Retrofit Add-on	$810,000	$930,000
O&M Cost (300 $/MMBtu)	$64,800	$74,400
Annual Cost (1,600 $/MMBtu)	$345,600	$396,800
SCR Subtotal (1999 $)	$3,920,400	$4,501,200
SCR Subtotal Adjusted for 2020 $ [a]	$6,151,500	$7,062,833
Pre-heater for Exhaust	Cost Not Available [b]	Not Applicable
Emission Reduction Percent	85%	85%
Emission Reduction [c] (tpy)	91.74	122.44
Cost of Emission Reduction [d] ($/ton)	$67,054	$57,684

[a] *The inflation rate in the United States between 1999 and today is 56.91%, (U.S. Bureau of Labor Statistics), https://www.bls.gov/data/inflation_calculator.htm, July 2020.*

[b] *EQUI 1 would require a preheater for exhaust in lieu of a hot side ESP. The cost for the preheater was not available but is listed in the table in order to identify it as another cost with both capital and operating impacts.*

[c] *Emission reduction is based on actual average emissions from 2016–2019 of 107.93 tons of NO_x from EQUI 1 and 144.05 tons of NO_x from EQUI 3.*

[d] *Cost of emission reduction is rounded to the nearest whole dollar.*

The cost to retrofit EQUI 1 with SCR would be about $67,068 per ton of NO_x removed. That value does not include the cost to increase the heat of the ESP exhaust to a sufficient temperature for the catalyst. The cost to retrofit EQUI 3 with SCR would be about $57,684 per ton of NO_x removed. EQUI 3 uses a hot side ESP, which means the exhaust temperature may be high enough without additional heating for the catalyst reaction.

USEPA directly states that capital costs for SCR are significantly higher than other types of NO_x controls due to the large volume of catalyst that is required. The cost of the catalyst is listed as $283/cubic foot. In addition, retrofitting SCR to an existing unit can increase costs by over 30% (USEPA 2002). The space constraints at HPUC would also add costs due to the requirement to relocate items and demolish structures in order to find the space for additional pollution control equipment.

Since the dissolution of the Xcel Power Purchase Agreement for renewable power, all the boilers on site have seen a reduction in use, as evident in the summary of historical actual NO_x emissions contained in Table 3.

3.3.2 Wood-Fired Boiler EQUI 7 Additional NO_x Control

SCR is the only NO_x reduction technology reviewed for cost since EQUI 7 already uses SNCR and the design includes OFA. LNBs are not applicable to wood. The natural gas fired combustion stabilization burners are low NO_x, but the combustion stabilizing burners are not part of this assessment. No other technology was found for application to this boiler system.

In order for an SCR to work on EQUI 7, the current ESP system would need to be replaced with a hot side ESP or, as an alternative, the air stream could be reheated to achieve sufficient temperature for the catalyst reaction. Catalysts require temperatures ranging from 480 degrees Fahrenheit (°F) to 800°F (ICAC 1997). The exhaust temperature entering the existing ESP is at about 400°F and would not be expected to change significantly upon the exit of the ESP.

As indicated earlier, SCR is typically applied to large coal and natural gas fired electrical utility boilers sized larger than what HPUC operates. The fact sheet does say SCR can be effective for large industrial boilers if the capacity factor is high enough. USEPA only refers to applying SCR technology to coal and natural gas fired boilers.

The USEPA directly states that capital costs for SCR are significantly higher than other types of NO_x controls due to the large volume of catalyst that is required. The cost of the catalyst is listed as $283/cubic foot. In addition, retrofitting SCR to an existing unit can increase costs by over 30% (USEPA 2002).

Table 7 summarizes the cost of retrofitting EQUI 7 with an SCR NO_x control system. Costs are based on the USEPA “Air Pollution Control Technology Fact Sheet” for SCR, EPA-452/F-03-032, table 1a – Summary of Cost Information in $/MMBtu/hr (1999 Dollars) for Industrial Oil, Gas, and Wood boilers. EQUI 7 has a rated capacity of 230 MMBtu/hr. The fact sheet is included as Appendix D.

Table 7: EQUI 7 SCR NO_x Control Cost Estimate Summary

Parameter	EQUI 7 (230 MMBtu/hr)
Capital Cost (5,000 $/MMBtu)	$1,150,000
30% Retrofit Add-on	$345,000
O&M Cost (450 $/MMBtu)	$103,500
Annual Cost (700 $/MMBtu)	$161,000
SCR Subtotal (1999 $)	$1,759,500
SCR Subtotal Adjusted for 2020 $ [a]	$2,760,831
Pre-heater for Exhaust [b]	Cost Not Available
Emission Reduction (85% total which is 53.2% above the existing SNCR system at 31.8%)	53.2%
Emission Reduction [c] (tpy)	40.72
Cost of Emission Reduction [d] ($/ton)	$67,800

[a] *The inflation rate in the United States between 1999 and today is 56.91%, (U.S. Bureau of Labor Statistics), https://www.bls.gov/data/inflation_calculator.htm, July 2020)*

[b] *Preheater for exhaust in lieu of a hot side ESP. The cost for the preheater was not available but is listed in the table in order to identify it as another cost with both capital and operating impacts.*

[c] *Emission reduction is based on 2016 emissions of 87.0 tons of NO_x, which could be reduced by an additional 53.2% by retrofitting EQUI 7 with SCR for NO_x reduction.*

[d] *Cost of emission reduction is rounded to the nearest whole dollar.*

The cost to retrofit EQUI 7 with SCR would be about $67,800 per ton of NO_x removed. That value does not include the cost to increase the heat of the ESP exhaust to a sufficient temperature for the catalyst. Since the dissolution of the Xcel Power Purchase Agreement for renewable power, the wood boiler has seen a reduction in use, as evident in the summary of historical actual NO_x emissions contained in Table 3. It is also the intent of HPUC to not operate the wood boiler going forward. At this time, there are no plans to remove boiler EQUI 7 from the operating permit.

3.4 Time to Implement Controls

To implement any of the controls discussed the following steps, and their duration, would need to be completed by HPUC:

- Budgetary design and project approval (12 months);
- Detailed engineering design and bid documents (6 to 9 months);
- Bid solicitation, evaluation, and selection (3 to 4 months);
- Procurement/contracting (3 to 4 months);
- Construction (6 to 10 months); and
- Commissioning (2 to 3 months).

This leads to an overall schedule of 32 to 42 months from concept to operation. HPUC is a governmental institution that requires formal approval from commission for any funding to occur.

3.5 Non-Air Quality Impacts

This section outlines in general terms the non-air quality related impacts that would result from implementing control technologies on the boilers. Table 8 and 9 show the impacts in general terms. For example, SCR for NO_x control (Table 6) uses a catalyst that is made from various ceramic materials, such as titanium oxide or oxides of base metals (such as vanadium, molybdenum, and tungsten), zeolites, or various precious metals. Mining to obtain catalyst materials has environmental implications.

Table 8: Impacts of Potential SO_x Control Technologies

Technology	EQUI 1	EQUI 3
Electrical Energy Consumption	Yes	Yes
Transportation Impacts	Yes	Yes
Solid Waste Generation	Yes	Yes
Increased Water Consumption	Yes	Yes

Table 9: Impacts of Potential NO_x Control Technologies

Technology	EQUI 1 – SNCR or SCR	EQUI 3 – SNCR or SCR	EQUI 7 - SCR
Electrical Energy Consumption	Yes	Yes	Yes
Transportation Impacts	Yes	Yes	Yes
Solid Waste Generation	Yes	Yes	Yes
Increased Water Consumption	Yes	Yes	Yes

In addition, retrofitting any of the boilers with additional emission control equipment will result in greenhouse gas emissions from construction, truck traffic, material manufacturing, and electrical use. Assuming that the electricity to power the control systems is from some fossil fuel-fired generation, then the increased electrical demand would result in greenhouse gas emissions.

3.6 Remaining Useful Life

EQUI 7 began operating in 2006, and the expectation is that it will last about 25 to 30 years with proper maintenance. That means the remaining useful life of EQUI 7 is greater than 10 years. EQUI 1 and EQUI 2 were installed in 1953, and EQUI 3 was installed around 1972. All three of the coal-fired boilers on site are well past what is deemed as a typical useful life. The boilers are continuously maintained with periodic replacement of components on as needed basis. Based on the years of service of the coal-fired boilers at HPUC, they are well beyond the conventional useful life age typically associated with boilers.

4. SUMMARY

The review of available information suggests that the cost criteria for visibility improvement is less than that for BACT; however, the target values for economic feasibility are generally not published and are evaluated on a case-by-case basis. The USEPA "Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period" (EPA-457/P-16-001, July 2016) provides guidance for states to establish control evaluation criteria, such as:

> "*…measures that cost less than $X/ton and that result in either (1) a visibility benefit greater than Y deciview at the most impacted Class I area or (2) cumulative visibility benefits across multiple affected Class I areas greater than Z deciview*."

4.1 Coal-Fired Boiler – EQUI 1 and EQUI 3 SO_2 Control

Adding SO_2 control to EQUI 1 and/or EQUI 3 at HPUC could be achieved by either installing a wet scrubber or spray dry scrubber. The cost of FGD technology has been calculated at $2,711,339 per ton of SO_2 removed for EQUI 1 and $3,323,998 per ton of SO_2 removed for EQUI 3. The cost of a spray dryer system not included the downstream fabric filter has been calculated to be over $3,218,974 per ton of SO_2 removed for EQUI 1 and over $3,946,438 per ton of SO_2 removed for EQUI 3. Both technologies, based on how the boilers are currently being operated, should be considered cost-prohibitive for visibility protection.

4.2 Coal-Fired Boiler – EQUI 1 and EQUI 3 NO_x Control

Reducing NO_x emissions from the EQUI 1 and/or EQUI 3 at HPUC could be achieved by either installing SNCR or SCR. The cost of SNCR technology has been calculated at $18,966 per ton of NO_x removed for EQUI 1 and $15,443 per ton of NO_x removed for EQUI 3. The cost of an SCR system has been calculated to be over $67,054 per ton of NO_x removed for EQUI 1 and over $57,684 per ton of NO_x removed for EQUI 3. Both technologies, based on how the boilers are currently being operated, should be considered cost-prohibitive for visibility protection.

4.3 Wood Boiler - EQUI 7 NO_x Control

In the case of further reducing NO_x emissions from the EQUI 7 at HPUC, the only available technology would be to replace the SNCR system with SCR. The cost of an SCR system has been calculated to be over $67,800 per ton of NO_x removed. This level of cost effectiveness would not be considered cost-effective for BACT control, and should be considered cost-prohibitive for visibility protection.

APPENDIX A SITE LOCATION MAP

APPENDIX B RACT/BACT/LAER SUMMARY

APPENDIX C USEPA AIR CONTROL TECHNOLOGY SNCR FACT SHEET

APPENDIX D USEPA AIR CONTROL TECHNOLOGY SCR FACT SHEET

APPENDIX E EXCERPTS FROM FOSTER WHEELER OPERATORS MANUAL

APPENDIX F USEPA AIR CONTROL TECHNOLOGY FGD FACT SHEET

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Hibbing Public Utilities

HIBBING PUBLIC UTILITIES COMMISSION

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TELEPHONE 218-262-7700
FAX 218-262-7702

July 1, 2022

Mr. Hassan Bouchareb, Engineer
Minnesota Pollution Control Agency (MPCA)
520 Lafayette Road North
St. Paul MN, 55155

Re: Operational Plans for Coal Fired Boilers #1 and #3A (EQUI 1 and 3)

Dear Mr. Bouchareb,

Hibbing Public Utilities Commission (HPUC), created under the framework set forth under MN Statue Section 412.321-391, has adopted its Environmental, Social, and Governance ES&G plan by Resolution dated May 24th . This resolution specifically states that from all points forward coal shall be a backup / emergency only fuel.

In addition to the Resolution, HPUC's specific context with its equipment and the applicability of a federally enforceable limits are addressed in a technical memorandum authored by Ms. Ann Curnow, ERM and myself. The memo addresses HPUC's continued progress towards its ES&G goals and current state of transition from ahistorical coal-based business model towards one that relies on coal as a backup / emergency only fuel in favor of local, renewable alternatives.

Please contact us with any questions on the attached.

Sincerely,

HIBBING PUBLIC UTILITIES COMMISSION

Luke J. Peterson

Luke J. Peterson,
General Manager

LJP/plr

At the Regular Hibbing Public Utilities Commission Meeting held __May 24th________, 2022 at 5:00 p.m. at the Hibbing City Hall Council Chamber, Commissioner _Bayliss___, offered the following resolution.

RESOLUTION OF SUPPORT FOR THE HIBBING PUBLIC UTILITIES RESTORATIVE UTILITY PLAN IN SUPPORT OF ITS ENVIRONMENTAL, SOCIAL AND GOVERNANCE GOALS

WHEREAS, The Hibbing Public Utilities Commission (HPUC) is an arm of the City of Hibbing created by special statute pursuant to the framework as set forth under Minn. Stat. Sect. 412.321 to 412.391; and,

WHEREAS, The HPUC seeks to continue its goals of providing quality utilities to all of its customers but doing so in a manner that will be least intrusive to the environment around us, and in a socially productive way to provide affordable services to all its customers; and,

WHEREAS, The HPUC recently received a presentation as to why using renewable resources such as wood as being a primary heat resource is environmentally friendly but also has the potential of providing a number of potential "spinoff" industries to take advantage of this resource with the potential of providing quality jobs in other industries as a result; and,

WHEREAS, The presentation known as the Hibbing Public Utilities Restorative Plan would be based on a wood gas fuel basis generating 20 megawatts of power 24 hours a day, 7 days a week, 365 days of the year can help the HPUC meet its environmental, social and governance baseline (goals); and,

WHEREAS, That by adopting on operations system based on wood and gas, HPUC will be in a position to contribute both to lower cost electrical and steam production in Hibbing, and HPUC will also make progress toward best in class compliance with Regional Haze Standards as set out by the Federal Environmental Protection Agency; and,

WHEREAS, By relying on coal as a backup/emergency fuel, the HPUC will also continue to have all options available to it to better protect its customers from global supply shock of natural gas price fluctuations and power grid volatility. This will also allow the HPUC to keep the ability to burn coal in its air permit and avoid costly pollution control equipment for a fuel source that is not a planned baseload fuel.

NOW THEREFORE, IT IS HEREBY RESOLVED, That the Hibbing Public Utilities Commission adopts the Hibbing Public Utilities Restorative Development Plan based on generating 20 megawatts of power through a wood/gas burning concept generating 20 megawatts 24 hours a day, 7 days a week, 365 days a year for long term utility planning.

The motion to adopt the foregoing resolution was duly supported by Commissioner Hart and upon being put to a vote, it passed as follows:

FOR ADOPTION:
Chair Hart Vice Chair Garrity
Commissioner Babich Commissioner Bayliss
Commissioner Andria

AGAINST ADOPTION:
None

ABSTAINING:
None

ABSENT:
None

Passed and adopted this 24 day of May, 2022.

CITY OF HIBBING

Jeff Hart, Chair

ATTEST:

Patrick L Garrity

Patrick L. Garrity, Vice Chair

ERM

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Memo

To	Hassan Bouchareb, Minnesota Pollution Control Agency
From	Ann Curnow, ERM and Luke Peterson, Hibbing Public Utilities
Date	June 27, 2022
Reference	Regional Haze NOx Reduction – Four Factor Analysis Follow-up Hibbing Public Utilities – Permit No. 13700027-102
Subject	Operational Plans for Coal-Fired Boilers #1A and 3A (EQUI 1 and 3)

Dear Mr. Bouchareb,

This memorandum outlines how Hibbing Public Utilities (HPU) is addressing regional haze and nitrogen oxide (NO_x) reductions based on the Four Factor Analysis recently completed. The Minnesota Pollution Control Agency (MPCA) has requested that HPU provide a plan to reduce NO_x emissions which contribute to regional haze. NO_x as well as sulfur dioxide (SO_2) are contributors to regional haze and products of combustion from coal fired boilers.

BACKGROUND

In a letter dated February 14, 2020, the MPCA requested that the Hibbing Public Utilities Commission (HPUC) conduct a four-factor analysis of the NO_x and sulfur dioxide (SO_2) emissions from Boiler 1A (EQUI 1 / EU 001), Boiler 3A (EQUI 3 / EU 003) and Wood-Fired Boiler EQUI 7 (EU007). Boiler 2A (EQUI 2 / EU002) has a common stack with Boiler 1A but was not part of the Four Factor Analysis request. In a telephone conversation with the MPCA Regional Haze contact, Mr. Hassan Bouchareb, ERM was informed that Boiler 2A was not in the request because the base year triggering the review was 2016, and Boiler 2A did not operate in 2016.

A report was subsequently provided to outline the costs reducing NO_x and SO_2 from the boilers. The costs for adding SO_2 control was deemed cost prohibited for all of the boilers. The wood boiler already has NO_x control so additional NO_x reduction for that boiler was also deemed cost prohibitive. The wood fired boiler is not a source of appreciable SO_2 emissions.

OPERATIONS

HPU plans on making coal a backup fuel for boilers 1A and 3A. HPU has decided that coal needs to be kept as a viable fuel option in order continue to provide steam and electricity to the residents of Hibbing, Minnesota in an economically and sustainable manner. Sustainability includes the availability of a particular fuel. Based on current world conditions the availability of natural gas at a reasonable cost is not guaranteed.

Hibbing residents were overly burden in 2021 with the rapid rise in natural gas prices caused by the artic vortex and the state of Texas being ill prepared to manage the cold temperatures with their under designed infrastructure. Fuel prices, as well as even the availability of certain fuels, is difficult to predict and not in HPU's control. The only way to manage fuel availability and costs is to not be reliant on only one fuel type or source for a fuel.

Boiler 2A (EQUI 2) was not a focus of the regional haze review but it is currently only operated with natural gas. The air operating permit allows coal as an option, but the boiler requires some maintenance to actually operate using coal. The changes that would be required to allow for coal combustion again by Boiler 2A would likely trigger a major permit amendment and that is not something that HPU wants to pursue at this time.

NO$_x$ REDUCTION

The Four Factor Analysis indicated that selective catalytic reduction for NOx would achieve 40 percent reduction in NO$_x$ for Boiler 1A and Boiler 3A which is a reduction of approximately 100 tons per year of NO$_x$ based on the average emissions from 2016 through 2019 for these two boilers. This timeline is inclusive of when the boilers were being operated to satisfy a power purchase agreement with Xcel Energy to produce electricity. The contract with Xcel Energy was dissolved and the boilers are primarily used for steam production during the winter heating season, not electricity production. The cost of adding on controls for NO$_x$ reduction is considered cost prohibitive by HPU.

If the focus of NO$_x$ reduction is from NO$_x$ generated from coal combustion, then HPU believes relegating coal to a backup fuel results in achieving that goal. The intent of the HPU is to primarily satisfy steam and city electrical needs using the wood-fired boiler and supplement energy demand with natural gas as needed. Coal would be relegated to a fuel of last resort to be used when natural gas is too expensive or curtailed.

In 2021 the emissions of NO$_x$ from coal combustion in Boiler 1A was 3.14 tons and for Boiler 3A was 30.96 tons. The 2021 combined total NO$_x$ emissions from coal combustion was 34.10 tons.

HPU contends that requiring a federally enforceable limit is not necessary when the business plan is to move away from coal unless cost pressures or other fuel scarcity requires its use. With the increased demand of natural gas, and limited supply to meet world demand, the cost for that fuel is expected to rise. HPU needs to maintain the ability to be fuel flexible for the residents it serves.

CLOSING

HPU is willing to address this issue again in a couple of years once the wood boiler is fully vetted to take on the base demand for district steam heating and city electrical requirements. HPU is acknowledging that Boiler 2A, as it exists today, cannot be operated on coal without additional maintenance even if the permit allows coal combustion. The potential emissions of NO$_x$ for Boiler 2A combusting coal is 490 tons per year while that same boiler combusting natural gas has potential emissions of about 92 tons per year. Not being able to operate Boiler 2A with coal has a potential NO$_x$ emission reduction of about 400 tons per year. That with HPU's operating plan to relegate coal as a backup fuel for Boilers 1A and 3A should satisfy the MPCA goals for achieving lower NO$_x$ emissions from coal combustion.

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January 29, 2020

Julie Lucas, Environmental Manager
Hibbing Taconite Company
4950 County Highway 5 N
Hibbing, MN 55476

RE: Request for Information - Regional Haze Rule, Reasonable Progress, Four Factor Analysis

Dear Ms. Lucas:

The Minnesota Pollution Control Agency (MPCA) is currently preparing information for the second planning period (Round 2) comprehensive update to Minnesota's Regional Haze State Implementation Plan (SIP) as required by the Regional Haze Rule (40 CFR § 51.308). States are responsible for developing a Regional Haze SIP that addresses regional haze in each Class I area located within the state and in each Class I area located outside the state which may be affected by emissions from sources within the state. The Regional Haze SIP is required to identify existing facilities that cause or contribute to visibility impairment; analyze, identify, and apply federally-enforceable control strategies for those sources; and periodically demonstrate reasonable progress toward reaching visibility goals. States are also responsible for periodic comprehensive updates to their Regional Haze SIP that address these same topics. Minnesota's Round 2 Regional Haze SIP must be submitted to the U.S. Environmental Protection Agency (U.S. EPA) by July 31, 2021.

Minnesota has two Class I areas within its borders, the Boundary Waters Canoe Area Wilderness (BWCA) and Voyageurs National Park (Voyageurs). Other nearby Class I areas include Isle Royale National Park in Michigan. Therefore, Minnesota must prepare a Regional Haze SIP that identifies sources that cause or contribute to visibility impairment in these areas. To meet the core requirements for regional haze for these areas, Minnesota must submit a SIP that contains the plan elements and supporting documentation for all required analyses identified in 40 CFR § 51.308(f).

In the first planning period (Round 1), the focus of the Regional Haze Rule was on establishing Best Available Retrofit Technology (BART) for certain older sources and reasonable progress towards national visibility goals. In Round 2, there are no BART requirements; therefore, the focus is on making reasonable progress. The U.S. Environmental Protection agency has defined the methodology that states must use to determine what measures are necessary to make reasonable progress in 40 CFR § 51.308(f)(2). At minimum, the reasonable progress analysis must use the four factors identified in 40 CFR § 51.308(f)(2)(i) to evaluate and determine the emission reduction measures necessary to make reasonable progress. The four factors are:

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

Data from the IMPROVE monitoring sites at BWCA and Voyageurs indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X).

You are receiving this letter because your facility was identified as a significant source of NO_X and SO_2 and is located close enough to the BWCA or Voyageurs to potentially cause or contribute to visibility impairment in these Class I areas. Therefore, the MPCA requests that you prepare a "Four Factor Analysis" for the following emission units:

1. Pellet Indurating Furnace Line No 1 (EQUI 95 / EU 020) that addresses emissions of NO_X and SO_2
2. Pellet Indurating Furnace Line No 2 (EQUI 96 / EU 021) that addresses emissions of NO_X and SO_2
3. Pellet Indurating Furnace Line No 3 (EQUI 97 / EU 022) that addresses emissions of NO_X and SO_2

The analysis should be prepared using the U.S. Environmental Protection Agency guidance[1] that provides recommendations for how each of the factors should be determined.

Preparation of the comprehensive update to Minnesota's Regional Haze SIP will require extensive planning and review of sources in Minnesota. The MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to prepare the Regional Haze SIP. The MPCA expects air quality modeling of potential regional emissions reductions will be conducted beginning in spring 2020. I appreciate your attention to this matter and request that you **submit the Four Factor Analysis by July 31, 2020**.

If you have any questions regarding this matter, or would like to request a meeting to further discuss the contents of this letter, please contact me by phone at 651-757-2653 or by email at Hassan.Bouchareb@state.mn.us.

Sincerely,

Hassan Bouchareb

This document has been electronically signed.

Hassan M. Bouchareb
Engineer
Environmental Analysis and Outcomes Division

Cc: Tasha Niemi, Hibbing Taconite
Deepa de Alwis, MPCA
Cory Boeck, MPCA
Frank Kohlasch, MPCA
Agency Interest ID 1146

Address questions and submittals requested above to:

Hassan M. Bouchareb
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155-4194
(651) 757-2653
Hassan.Bouchareb@state.mn.us

---

[1] **U.S. Environmental Protection Agency.** *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 20, 2019, https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

Hibbing Taconite Company
Managed by ArcelorMittal Hibbing Management LLC

May 29, 2020

Hassan M. Bouchareb
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155-4194

**Re: ArcelorMittal Hibbing Taconite Company
Request for Information – Four Factor Analysis**

Mr. Bouchareb,

ArcelorMittal Hibbing Taconite Company (HTC) has prepared the enclosed Regional Haze Four-Factor Analysis Applicability Evaluation (Evaluation) in response to the Minnesota Pollution Control Agency's (MPCA) January 29, 2020 request for information and a Four Factor Analysis for the natural gas fired indurating furnace Lines 1-3 (EQUI 95-97/EU 020-022).

HTC respectfully requests MPCA timely withdraw its request for HTC to prepare a four-factor analysis for the natural gas fired indurating furnace Lines 1-3 which are already equipped with Newly Engineered Site-Specific Low NO_X Burner Technology and Taconite MACT scrubbers. The Evaluation provides evidence for MPCA to exclude HTC from the group of sources analyzed for control measures for the second implementation period and to withdraw its request for a Four Factor Analysis.

Should you have any questions or comments regarding this submittal, please contact Julie Lucas, Environmental Manager, by telephone at 218-262-6856 or via email at julie.lucas@arcelormittal.com

Sincerely,

Edward M LaTend

Edward M. LaTendresse
General Manager

cc: Julie C. Lucas (ArcelorMittal USA)
Rich Zavoda (ArcelorMittal USA)

Regional Haze Four-Factor Analysis Applicability Evaluation

Natural Gas Fired Indurating Furnace Lines 1-3 Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT Scrubbers (EQUI 95-97/EU 020-022)

Prepared for
Hibbing Taconite Company

May 29, 2020

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Duluth, MN 55802
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Regional Haze Four-Factor Analysis Applicability Evaluation

May 29, 2020

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Appendix A Visibility Impacts

1 Executive Summary

On January 29, 2020 the Minnesota Pollution Control Agency (MPCA) submitted a Request for Information (RFI) Letter[1] to Hibbing Taconite Company (HTC) to consider potential emissions reduction measures of nitrogen oxides (NO_X) and sulfur dioxide (SO_2) from the facility's indurating furnaces by addressing the four statutory factors laid out in 40 CFR 51.308(f)(2)(i), as explained in the August 2019 U.S. EPA Guidance (2019 Guidance)[2]:

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

Emission reduction evaluations addressing these factors are commonly referred to as "four-factor analyses." MPCA set a July 31, 2020 deadline for HTC to submit a four-factor analysis. The MPCA intends to use the four-factor analyses to evaluate additional control measures as part of the development of the State Implementation Plan (SIP), which must be submitted to United States Environmental Protection Agency (USEPA) by July 31, 2021. The SIP will be prepared to address the second regional haze implementation period, which ends in 2028.

This report considers whether a four-factor analysis is warranted for HTC because the indurating furnace Lines 1-3 can be classified as "effectively controlled" sources for NO_x and SO_2. The MPCA can exclude such sources for evaluation per the regulatory requirements of the Regional Haze Rule[3] (RHR) and the 2019 Guidance.

This report provides evidence that it would be reasonable for MPCA to exclude HTC from the group of sources analyzed for control measures for the second implementation period and to withdraw its request for a four-factor analysis for the indurating furnace Lines 1-3 based on the following points (with additional details provided in cited report sections):

- The indurating furnace Lines 1-3 meet the BART-required control equipment installation scenario and are "effectively controlled" sources for NO_x and SO_2. HTC has BART emission controls and emission limits for NO_X and SO_2 in accordance with 40 CFR 52.1235(b)(1) and 52.1235(b)(2), respectively. The associated BART analyses are provided in the August 2012[4] and October 2015[5] USEPA Federal Implementation Plan (FIP) rulemaking. (see Section 5)

---

[1] January 29, 2020 letter from Hassan Bouchareb of MPCA to Hibbing Taconite Company.

[2] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[3] USEPA, Regional Haze Rule Requirements – Long Term Strategy for Regional Haze, 40 CFR 52.308(f)(2)

[4] USEPA, Federal Register, 08/15/2012, Page 49308.

[5] USEPA, Federal Register, 10/22/2015, Page 64160.

- The RHR and the 2019 Guidance both give states the ability to focus their analyses in one implementation period on a set of sources that differ from those analyzed in another implementation period. (see Section 2.1.3.2)

- There has been significant progress on visibility improvement in the nearby Class I areas and MPCA's reasonable progress goals should be commensurate with this progress. (see Section 3.1)

- The indurating furnace Lines 1-3 do not materially impact visibility from a theoretical (modeling) and empirical (actual visibility data) basis and should not be required to assess additional emission control measures. (see Section 4)

Additional emission reductions from the indurating furnace Lines 1-3 at HTC will not contribute meaningfully to further reasonable progress. **Therefore, HTC respectfully requests that the MPCA timely withdraw its request for a four-factor analysis for the natural gas fired indurating furnace Lines 1-3 already equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT scrubbers.**

2 Introduction

Section 2.1 discusses the RFI provided to HTC by MPCA, pertinent regulatory background for regional haze State Implementation Plans (SIP) development and relevant guidance issued by USEPA to assist States in preparing their SIPs, specifically regarding the selection of sources that must conduct an emissions control evaluation. Section 2.2 provides a description of HTC's indurating furnaces.

2.1 Regulatory Background

2.1.1 Minnesota's Request for Information (RFI)

"Regional haze" is defined at 40 CFR 51.301 as "visibility impairment that is caused by the emission of air pollutants from numerous anthropogenic sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources." The RHR requires state regulatory agencies to submit a series of SIPs in ten-year increments to protect visibility in certain national parks and wilderness areas, known as mandatory Federal Class I areas. The original State SIPs were due on December 17, 2007 and included milestones for establishing reasonable progress towards the visibility improvement goals, with the ultimate goal to achieve natural background visibility by 2064. The initial SIP was informed by best available retrofit technology (BART) analyses that were completed on all BART-subject sources. The second RHR implementation period ends in 2028 and requires development and submittal of a comprehensive SIP update by July 31, 2021.

As part of the second RHR implementation period SIP development, the MPCA sent an RFI to HTC on January 29, 2020. The RFI stated that data from the IMPROVE (Interagency Monitoring of Protected Visual Environments) monitoring sites at Boundary Waters Canoe Area (BWCA) and Voyageurs National Park (Voyageurs) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of SO_2 and NO_X that react with available ammonia. In addition, emissions from sources in Minnesota could potentially impact Class I areas in nearby states, namely Isle Royale National Park (Isle Royale) in Michigan.[6] As part of the planning process for the SIP development, MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to evaluate regional emission reductions.

The RFI also stated that HTC was identified as a significant source of NO_X and SO_2 and is located close enough to the BWCA and Voyageurs to potentially cause or contribute to visibility impairment. Therefore, the MPCA requested that HTC submit a "four-factors analysis" (herein termed as a "four-factor analysis") evaluating potential emissions control measures, pursuant to 40 CFR 51.308(f)(2)(i)[7], by July 31, 2020 for the emission units identified in Table 2-1.

---

[6] Although Michigan is responsible for evaluating haze in Isle Royale, it must consult with surrounding states, including Minnesota, on potential cross-state haze pollution impacts.

[7] The four statutory factors are 1) cost of compliance, 2) time necessary for compliance, 3) energy and non-air quality environmental impacts of compliance, and 4) remaining useful life of the source.

Table 2-1 Identified Emission Units

Unit	Unit ID	Applicable Pollutants
Natural Gas Fired Indurating Furnace Line No 1 Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT Scrubbers	EQUI 95/EU 020	NO_X, SO_2
Natural Gas Fired Indurating Furnace Line No 2 Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT Scrubbers	EQUI 96/EU 021	NO_X, SO_2
Natural Gas Fired Indurating Furnace Line No 3 Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT Scrubbers	EQUI 97/EU 022	NO_X, SO_2

The RFI to HTC specified that the "analysis should be prepared using the U.S. Environmental Protection Agency guidance" referring to USEPA guidance as issued on August 20, 2019[8].

2.1.2 SIP Revision Requirements

The regulatory requirements for comprehensive revisions to the SIP are provided in 40 CFR 51.308(f). The next revision must be submitted to USEPA by July 31, 2021 and must include a commitment to submit periodic reports describing progress towards the reasonable progress goals as detailed in 40 CFR 51.308(g). The SIP "must address regional haze in each mandatory Class I Federal area located within the State and in each mandatory Class I Federal area located outside the State that may be affected by emissions from within the State."

Each SIP revision is required to address several elements, including "calculations of baseline, current, and natural visibility conditions; progress to date; and the uniform rate of progress."[9] The baseline conditions are based on monitoring data from 2000 to 2004 while the target conditions for natural visibility are determined using USEPA guidance. The State will then determine the uniform rate of progress (URP) which compares "the baseline visibility condition for the most impaired days to the natural visibility condition for the most impaired days and determine the uniform rate of visibility improvement (measured in deciviews of improvement per year) that would need to be maintained during each implementation period in order to attain natural visibility conditions by the end of 2064."[10]

The SIP revision must also include the "Long-term strategy for regional haze."[11] The strategy "must include the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress" towards the natural visibility goal. There are several criteria that must be considered when developing the strategy, including an evaluation of emission controls (the four-factor analysis) at selected facilities to determine emission reductions necessary to make reasonable

---

[8] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[9] 40 CFR 51.308(f)(1)

[10] 40 CFR 51.308(f)(1)(vi)(A)

[11] 40 CFR 51.308(f)(2)

progress. The SIP must consider other factors in developing its long-term strategy, including: emission reductions due to other air pollution control programs[12], emission unit retirement and replacement schedules[13], and the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions during the implementation period[14].

In addition, the SIP must include "reasonable progress goals" that reflect the visibility conditions that are anticipated to be achieved by the end of the implementation period through the implementation of the long term strategy and other requirements of the Clean Air Act (CAA)[15]. The reasonable progress goal is not enforceable but will be considered by USEPA in evaluating the adequacy of the SIP[16].

2.1.3 USEPA Guidance for SIP Development

On August 20, 2019, the USEPA issued "*Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*"[17] USEPA's primary goal in issuing the 2019 Guidance was to help states develop "approvable" SIPs. EPA also stated that the document supports key principles in SIP development, such as "leveraging emission reductions achieved through CAA and other programs that further improve visibility in protected areas."[18]

The 2019 Guidance says SIPs must be "consistent with applicable requirements of the CAA and EPA regulations, and are the product of reasoned decision-making"[19] but also emphasizes States' discretion and flexibility in the development of their SIPs. For instance, the 2019 Guidance states, "A key flexibility of the regional haze program is that a state is *not* required to evaluate all sources of emissions in each implementation period. Instead, a state may reasonably select a set of sources for an analysis of control measures."[20] The 2019 Guidance notes this flexibility to not consider every emission source stems directly from CAA § 169A(b)(2) and 40 CFR § 51.308(f)(2)(i), the section of the RHR the MPCA cites in its letter.[21]

The 2019 Guidance lists eight key process steps that USEPA anticipates States will follow when developing their SIPs. This report focuses on the selection of sources which must conduct a four-factor analysis and references the following guidance elements which impact the selection:

- Ambient data analysis (Step 1), including the progress, degradation and URP glidepath checks (Step 7)

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[12] 51.308(f)(2)(iv)(A)

[13] 51.308(f)(2)(iv)(C)

[14] 51.308(f)(2)(iv)(E)

[15] 40 CFR 51.308(f)(3)

[16] 40 CFR 51.308(f)(3)(iii)

[17] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[18] Ibid, page 1.

[19] Ibid.

[20] Ibid, page 9 (emphasis added).

[21] Ibid.

- Selection of sources for analysis (Step 3), with a focus on:
    - Estimating baseline visibility impacts for source selection (Step 3b)
    - Sources that already have effective emission control technology in place (Step 3f)

2.1.3.1 Ambient Data Analysis

As stated in Section 2.1.2, the RHR requires each state with a Class I area to calculate the baseline, current, and natural visibility conditions as well as to determine the visibility progress to date and the URP. The visibility metric is based on the 20% most anthropogenically impaired days and the 20% clearest days, with visibility being measured in deciviews (dv). The guidance provides the following equation for calculating the Uniform Rate of Progress (URP):[22]

$$\text{URP} = [(\text{2000-2004 visibility})_{\text{20\% most impaired}} - (\text{natural visibility})_{\text{20\% most impaired}}]/60$$

The visibility from 2000-2004 represents the baseline period, and the natural visibility goal is in 2064, which is why the URP is calculated over a 60-year period.

At the end of the SIP development process a State must estimate the visibility conditions for the end of the implementation period and then must complete a comparison of the reasonable progress goals to the baseline visibility conditions and the URP glidepath. The guidance explains that the RHR does not define the URP as the target for "reasonable progress" and further states that if the 2028 estimate is below the URP glidepath, that does not exempt the State from considering the four-factor analysis for select sources.[23] However, the current visibility conditions compared to the URP glidepath will be a factor when determining the reasonable progress goal.

In Section 3, Barr evaluates the visibility improvement progress to date at BWCA, Voyageurs and Isle Royale using the IMPROVE network visibility data from MPCA's website. This analysis was conducted to document the current visibility conditions compared to the URP, which can provide insight into the amount of emission reductions necessary to have the 2028 visibility conditions below the URP.

2.1.3.2 Selection of sources for analysis

The 2019 Guidance emphasizes that the RHR provides flexibility in selecting sources that must conduct an emission control measures analysis:

> "…a state is not required to evaluate all sources of emissions in each implementation period. Instead, a state may reasonably select a set of sources for an analysis of control measures…."[24]

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[22] Ibid, Page 7.

[23] Ibid, Page 50.

[24] Ibid, Page 9.

The 2019 Guidance goes on to justify this approach (emphasis added):

> "Selecting a set of sources for analysis of control measures in each implementation period is also consistent with the Regional Haze Rule, which sets up an iterative planning process and anticipates that a state may not need to analyze control measures for all its sources in a given SIP revision. Specifically, section 51.308(f)(2)(i) of the Regional Haze Rule requires a SIP to include a description of the criteria the state has used to determine the sources or groups of sources it evaluated for potential controls. Accordingly, <u>it is reasonable and permissible for a state to distribute its own analytical work, and the compliance expenditures of source owners, over time by addressing some sources in the second implementation period and other sources in later periods</u>. For the sources that are not selected for an analysis of control measures for purposes of the second implementation period, it may be appropriate for a state to consider whether measures for such sources are necessary to make reasonable progress in later implementation periods."[25]

The 2019 Guidance further states that there is not a list of factors that a state must consider when selecting sources to evaluate control measures, but the state must choose factors and apply them in a reasonable way to make progress towards natural visibility. The guidance details several factors that could be considered, including:

- the in-place emission control measures and, by implication, the emission reductions that are possible to achieve at the source through additional measures[26]
- the four statutory factors (to the extent they have been characterized at this point in SIP development)[27]
- potential visibility benefits (also to the extent they have been characterized at this point in SIP development)[28]
- sources already having effective emissions controls in place[29]
- emission reductions at the source due to ongoing air pollution control programs[30]
- in-state emission reductions due to ongoing air pollution control programs that will result in an improvement in visibility[31]

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[25] Ibid, Page 9.

[26] Ibid, Page 10.

[27] Ibid.

[28] Ibid.

[29] Ibid, Page 21.

[30] Ibid, Page 22.

[31] Ibid.

Furthermore, the 2019 Guidance states that "An initial assessment of projected visibility impairment in 2028, considering growth and on-the books controls, can be a useful piece of information for states to consider as they decide how to select sources for control measure evaluation."[32]

2.1.3.2.1 Estimating Baseline Visibility Impacts for Source Selection

When selecting sources to conduct an emission control evaluation, the 2019 Guidance says that the state may use a "reasonable surrogate metrics of visibility impacts." The guidance provides the following techniques to consider and says that "other reasonable techniques" may also be considered[33]:

- Emissions divided by distance (Q/d)
- Trajectory analyses
- Residence time analyses
- Photochemical modeling

In regard to documenting the source selection process, the 2019 Guidance states:[34]

> "EPA recommends that this documentation and description provide both a summary of the state's source selection approach and a detailed description of how the state used technical information to select a reasonable set of sources for an analysis of control measures for the second implementation period. The state could include qualitative and quantitative information such as: the basis for the visibility impact thresholds the state used (if applicable), additional factors the state considered during its selection process, and any other relevant information."

In Section 4, Barr presents a trajectory analysis using data from the IMPROVE monitoring network as presented on MPCA's website and photochemical modeling results to demonstrate that it is not appropriate to select the taconite indurating furnaces as sources subject to the emissions control measures analysis because reducing the emissions will not have a large impact on visibility. Section 4 also presents information from the IMPROVE monitoring system which demonstrates that there was not a noticeable improvement in visibility in 2009 when the taconite plants experienced a production curtailment due to a recession which indicates that the reduction of pollutants from taconite facilities will not result in a discernable visibility improvement in the Class 1 areas.

2.1.3.3 Sources that Already have Effective Emission Control Technology in Place

The 2019 Guidance identified eight example scenarios and described the associated rationale for when sources should be considered "effectively controlled" and that states can exclude similar sources from needing to complete a "four-factor analysis."[35] One of the "effectively controlled" scenarios is for "BART-

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[32] Ibid, Page 10.

[33] Ibid, Page 12.

[34] Ibid, Page 27.

[35] Ibid, Page 22.

eligible units that installed and began operating controls to meet BART emission limits for the first implementation period."[36] USEPA caveats this scenario by clarifying that "states may not categorically exclude all BART-eligible sources, or all sources that installed BART control, as candidates for selection for analysis of control measures."[37] USEPA further notes that "a state might, however, have a different, reasonable basis for not selecting such sources [BART-eligible and non-BART eligible units that implement BART controls] for control measure analysis."[38]

In Section 5, Barr presents an evaluation of the BART-eligible units scenario and demonstrates that the indurating furnace Lines 1-3 are "effectively controlled" sources for both NO_X and SO_2. Thus, a four-factor analysis is not warranted for this source because, as USEPA notes, "it may be unlikely that there will be further available reasonable controls for such sources."[39]

2.2 Facility Description

HTC mines iron ore (magnetite) and produces taconite pellets that are shipped to steel producers for processing in blast furnaces. The iron ore is crushed and routed through several concentration stages including grinding, magnetic separation, and thickening.

A concentrated iron ore slurry is dewatered by vacuum disk filters, mixed with bentonite, and conveyed to balling drums. Greenballs produced on the balling drums are distributed evenly across pallet cars prior to entry into the pellet furnace. The pallet cars have a layer of fired pellets, called the hearth layer, on the bottom and sides of the car. The hearth layer acts as a buffer between the pallet car and the heat generated through the exothermic conversion of magnetite to hematite.

HTC operates three natural gas fired indurating furnace lines, with fuel oil as a back-up for emergency purposes. Natural gas has been the only fuel combusted at the indurating furnaces in the last 20 years. Each Line is a straight-grate induration furnace design. The first two zones are updraft and downdraft drying zones. The next zones are the preheat zone and firing zone. The temperature increases as the pellets pass through each zone, reaching a peak in the firing zone. The conversion of magnetite to hematite is completed in the firing zone. The last two zones are cooling zones that allow the pellets to be safely discharged.

Heated air discharged from the two cooling zones is recirculated to the drying, preheat and firing zones. Flue gas from the furnaces are vented primarily through two ducts, the hood exhaust that handles the drying and recirculated cooling gases, and the windbox exhaust, which handles the preheat and firing gases. The windbox flue gas flows through the multiclones, and then enters a common header shared with the hood flue gas stream. The flue gases are subsequently divided into four streams which lead to

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[36] Ibid, Page 25.

[37] Ibid.

[38] Ibid.

[39] Ibid.

four Taconite Maximum Achievable Control Technology (MACT) venturi rod wet scrubbers and exit from four individual stacks. An overview of the furnace design is provided on Figure 2-1.

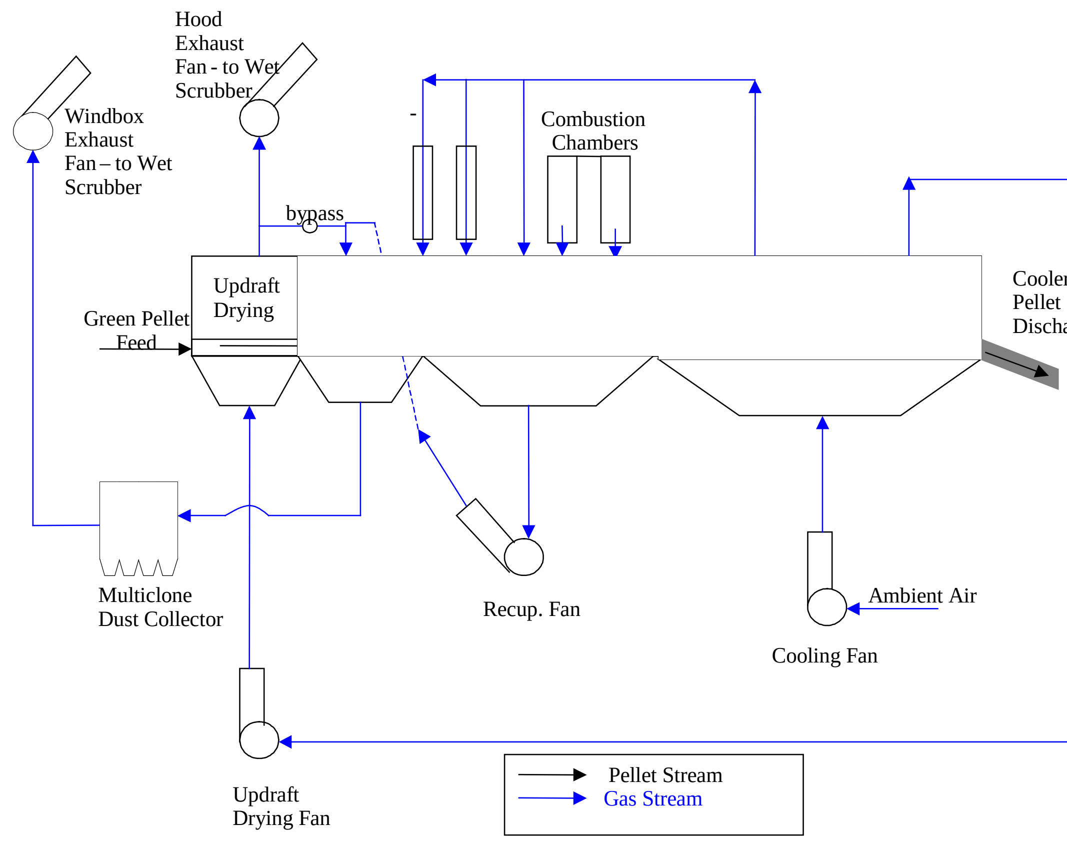

Figure 2-1 Natural Gas Fired Straight Grate Furnace Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT Scrubbers Diagram

3 Analysis of Ambient Data

As described in Section 2.1.2, the SIP must consider visibility conditions (baseline, current, and natural visibility), progress to date, and the URP. This requirement is referred to as Step 1 on the 2019 Guidance (see Section 2.1.3.1). This information informs the State's long term strategy for regional haze, as required by 51.308(f)(2), and the reasonable progress goals, as required by 51.308(3).

Section 3.1 provides analysis of visibility conditions based on data from the IMPROVE monitoring network at BWCA (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1) and Section 3.2 addresses regional emission reductions. Consistent with 51.308(f)(2)(iv), the regional emission reductions summary considers emission reductions that have occurred but are not yet reflected in the available 5-year average monitoring data set and future emission reductions that will occur prior 2028, which is the end of the second SIP implementation period.

3.1 Visibility Conditions

As summarized in Section 2.1.2, the RHR requires that the SIP include an analysis "of baseline, current, and natural visibility conditions; progress to date; and the uniform rate of progress."[40] This data will be used in the SIP to establish reasonable progress goals (expressed in deciviews) that reflect the visibility conditions that are projected to be achieved by the end of the implementation period (2028) as a result of the implementation of the SIP and the implementation of other regulatory requirements.[41] The reasonable progress goal is determined by comparing the baseline visibility conditions to natural visibility conditions and determining the uniform rate of visibility improvement needed to attain natural visibility conditions by 2064. The SIP "must consider the uniform rate of improvement in visibility and the emission-reduction measures needed to achieve it for the period covered by the implementation plan."[42]

MPCA tracks progress towards the natural visibility conditions using data from the IMPROVE visibility monitors at BWCA (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1).[43] The available regional haze monitoring data was compared to the uniform rate of progress and to the possible reasonable progress goals for the SIP for the implementation period, which ends in 2028. As described in Section 2.1.3.1, the visibility metric is based on the 20% most anthropogenically impaired days and the 20% clearest days, with visibility being measured in deciviews (dv). USEPA issued guidance for tracking visibility progress, including the methods for selecting the "most impaired days," on December 20, 2018.[44] Originally, the RHR considered the "haziest days" but USEPA recognized that naturally occurring events (e.g., wildfires and dust storms) could be contributing to visibility and that the "visibility improvements resulting from decreases in anthropogenic emissions can be hidden in this uncontrollable natural variability."[45] In

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[40] 40 CFR 51.308(f)(1)

[41] 40 CFR 51.308(f)(3)

[42] 40 CFR 51.308(d)(1)

[43] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

[44] https://www.epa.gov/visibility/technical-guidance-tracking-visibility-progress-second-implementation-period-regional

[45] USEPA, Federal Register, 05/04/2016, Page 26948

addition, the RHR allows a state to account for international emissions "to avoid any perception that a state should be aiming to compensate for impacts from international anthropogenic sources."[46]

Figure 3-1 through Figure 3-3 show the rolling 5-year average of visibility impairment versus the URP glidepath[47] at BWCA (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1). Regional haze impairment has been declining since 2009 for all three Class I areas that are tracked by MPCA. Impacts to the most impaired days at BWCA and Isle Royale fell below the expected 2028 URP goal in 2016 and have continued trending downward since. Voyageurs impaired days fell below the 2028 URP in 2018 and is also on a downward trend.

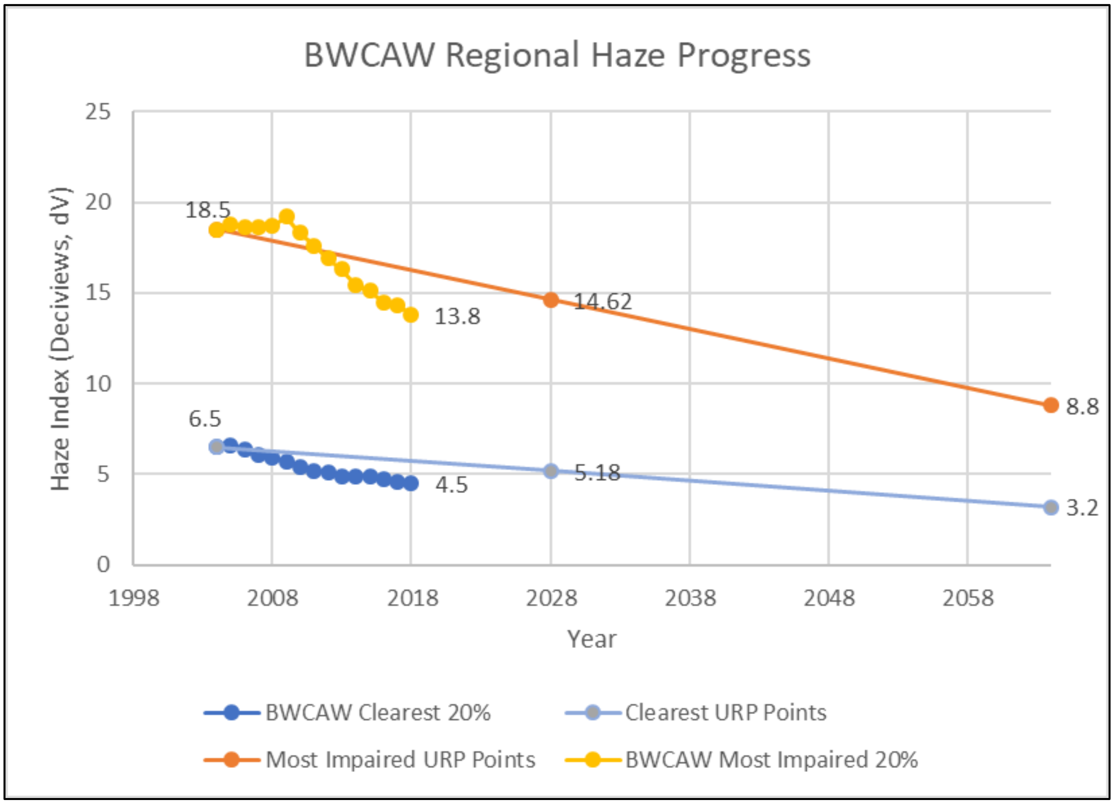

Figure 3-1 Visibility Trend versus URP – Boundary Waters Canoe Area (BOWA1)

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[46] USEPA, Federal Register, 01/10/2017, Page 3104

[47] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

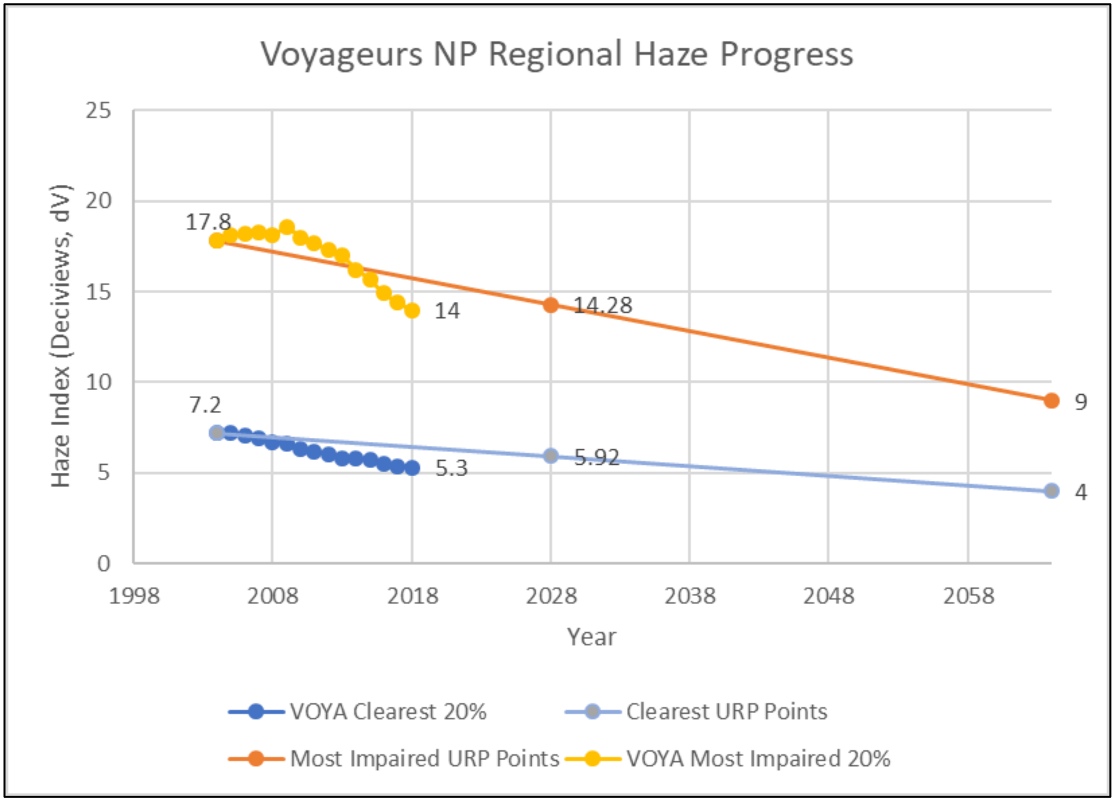

Figure 3-2 Visibility Trend versus URP – Voyageurs National Park (VOYA1)

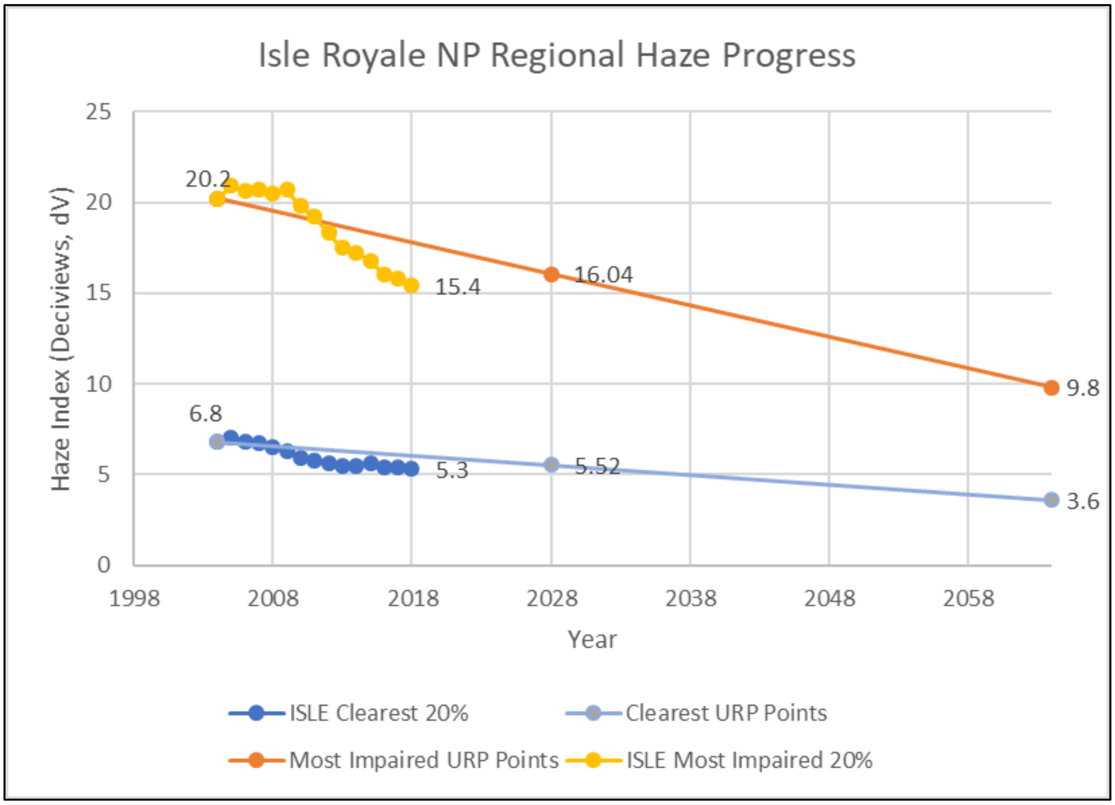

Figure 3-3 Visibility Trend versus URP – Isle Royale National Park (ISLE1)

3.2 Regional emissions reductions

The visibility improvement shown in Figure 3-1 through Figure 3-3 correlates with SO_2 and NO_x emissions decreases from Minnesota's top twenty emission stationary sources, as shown in Figure 3-4[48]. These emission reductions are a result of multiple substantial efforts from the regulated community, including:

- Installation of BART controls during the first implementation period
- Emission reductions at electric utility combustion sources due to new rules and regulations, including:
  - Acid Rain Rules
  - Cross State Air Pollution Rule (CASPR)
  - Mercury and Air Toxics Standards (MATS)
- Electric utility combustion sources undergoing fuel changes (e.g., from coal and to natural gas)
- Increased generation of renewable energy, which decreases reliance on combustion sources

Since many of these emission reduction efforts are due to federal regulations and national trends in electrical generation, similar emission reduction trends are likely occurring in other states.

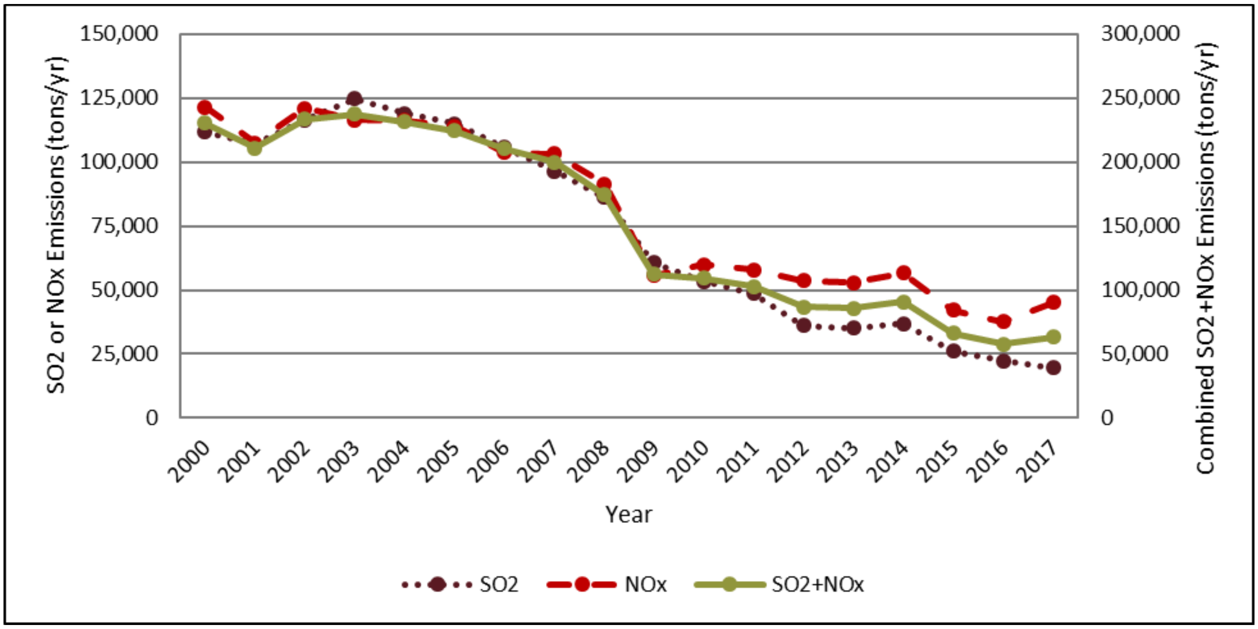

Figure 3-4 Total Emissions of Top-20 Emitters and Taconite Facilities in MN (2000-2017)

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[48] The data for NO_X and SO_2 emissions was downloaded from the MPCA point source emissions inventory (https://www.pca.state.mn.us/air/permitted-facility-air-emissions-data). The permitted facilities that had the 20 highest cumulative emissions from 2000-2017 in MN were chosen for the graphics, along with all six taconite facilities (whether or not they were in the top 20 of the state).

Figure 3-1 through Figure 3-3 show the rolling 5-year average of visibility impairment versus the URP glidepath, so the emissions represented in the most recent data set (2018) is from 2014-2018. However, as shown in Table 3-1, additional emission reductions have occurred since 2014 and are not fully represented in the 5-year visibility data yet. Additionally, several stationary sources have scheduled future emission reductions which will occur prior to 2028. Combined, these current and scheduled emission reductions will further improve visibility in the Class I areas, ensuring the trend stays below the URP. Even without these planned emissions reductions, the 2018 visibility data is already below the 2028 glidepath. As such, MPCA's second SIP implementation period strategy should be commensurate with the region's visibility progress and it would be reasonable for MPCA to not include the taconite indurating furnaces when "reasonably select[ing] a set of sources for an analysis of control measures," and such decision is supported by the 2019 Guidance.

Table 3-1 Notable Minnesota Emission Reductions

Year	Additional Emissions Reductions Expected/Projected
2015	MP Laskin: converted from coal to natural gas**
2017	Minntac Line 6: FIP emission limit compliance date for NO_X*
2018	Minntac Line 7: FIP emission limit compliance date for NO_X* MP Boswell: Units 1 & 2 retired from service**
2019	Hibtac Line 1: FIP emission limit compliance date for NO_X* Keetac: FIP emission limit compliance date for NO_X * Minntac Line 4 or 5: FIP emission limit compliance date for NO_X* Utac Line 1: FIP emission limit compliance date for NO_X*
2020	Hibtac Line 2: FIP emission limit compliance date for NO_X* Minntac Line 4 or 5: FIP emission limit compliance date for NO_X* Minorca: FIP emission limit compliance date for NO_X* Utac Line 2: FIP emission limit compliance date for NO_X*
2021	Minntac Line: FIP emission limit compliance date for NO_X* Hibtac Line 3: FIP emission limit compliance date for NO_X*
2023	Xcel: Sherco Unit 2 Retirement***
2026	Xcel: Sherco Unit 1 Retirement***
2028	Xcel: Allen S. King Plant Retirement***
2030	Xcel: Sherco Unit 3 Retirement, Xcel target to emit 80% less carbon by 2030***
2050	Xcel: Energy targeting carbon free generation by 2050***

* FIP is the regional haze Federal Implementation Plan detailed in 40 CFR 52.1235
** Minnesota Power - Integrated Resource Plan 2015-2029
*** Xcel Energy - Upper Midwest Integrated Resource Plan 2020-2034.

4 Visibility Impacts

As described in Section 2.1.3.2, the 2019 Guidance outlines criteria to evaluate when selecting sources that must complete an analysis of emission controls. The 2019 Guidance is clear that a state does not need to evaluate all sources of emissions but "may reasonably select a set of sources for an analysis of control measures" to make progress towards natural visibility.

As described in Section 2.1.3.2.1, the 2019 Guidance provides recommendations on selecting sources by estimating baseline visibility impacts. Three of the options for estimating baseline visibility impacts are analyzed below:

- *Trajectory analyses*[49]
  In general, these analyses consider the wind direction and the location of the Class I areas to identify which sources tend to emit pollutants upwind of Class I areas. The 2019 Guidance says that a state can consider "back trajectories" which "start at the Class I area and go backwards in time to examine the path that emissions took to get to the Class I areas." Section A1.1 of Appendix A, describes the back trajectory analysis and concludes the taconite indurating furnaces were a marginal contributor to the "most impaired" days from 2009 and 2011-2015. The trajectory analysis also indicates many sources other than the taconite facilities were significant contributors to the "most impaired" days.

- *Photochemical modeling*[50]
  The 2019 Guidance says, "states can also use a photochemical model to quantify source or source sector visibility impacts." CAMx modeling was previously conducted to identify visibility impacts in Class I areas from Minnesota taconite facilities from NOx emission reductions. This analysis is summarized in Section A1.2 of Appendix A which concludes the Class I areas near the Iron Range will not experience any observable visibility improvements from NO_X emission reductions suggested by the USEPA in the final Regional Haze FIP for taconite indurating furnaces.

- *Other reasonable techniques*[51]
  In addition to the two analyses described above which estimate the baseline visibility impacts, Section A1.3 of Appendix A evaluates the actual visibility data against the 2009 economic recession impacts on visibility, when taconite facilities curtailed production. This curtailment resulted in a decrease in emissions from the collective group of taconite plant and the regional power production that is needed to operate the plants. The IMPROVE monitoring data during this curtailment period was compared to monitoring data during more typical production at the taconite plants to estimate the taconite facilities' actual (rather than modeled) impact on haze. This analysis concludes "haze levels in BWCA did not, in general, decrease during 2009, and were therefore unaffected by emission reductions associated with the taconite production slowdown. It

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[49] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, Page 13.

[50] Ibid, Page 14.

[51] Ibid, Page 12.

is noteworthy that peak events during mid-2009 in sulfate haze at BWCA when very little taconite production was occurring clearly indicate that minimal haze reduction would likely be associated with taconite plant emission reductions."[52] The report further notes "high nitrate haze days late in 2009 with the taconite plant curtailment that are comparable in magnitude to full taconite production periods in 2008. We also note that after the taconite plants went back to full production in 2010, the haze levels dropped, apparently due to emissions from other sources and/or states."[53]

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[52] AECOM, "Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas," 09/28/2012, Page 10.

[53] Ibid, Page 12.

5 Evaluation of “Effectively Controlled” Source

As described in Section 2.1.3.3, the 2019 Guidance acknowledges that states may forgo requiring facilities to complete the detailed four-factor analysis if the source already has “effective emission control technology in place.”[54] This section demonstrates that the indurating furnace Lines 1-3 meet USEPA’s BART-required control equipment installation scenario for NO_X and SO_2.

The indurating furnace Lines 1-3 meet this scenario as “effectively controlled” sources because:

- The indurating furnace Lines 1-3 are BART-eligible units, as determined by Minnesota’s December 2009 Regional Haze Plan, and are regulated under 40 CFR 52.1235 (Approval and Promulgation of Implementation Plans – Subpart Y Minnesota – Regional Haze)
- The indurating furnace Lines 1-3 have controls and must “meet BART emission limits for the first implementation period”[55] for NO_X and SO_2

The following sections describe USEPA’s BART determinations, the associated controls that were implemented as BART, and the resulting BART emission limits for NO_X and SO_2.

5.1 NO_X BART-required Controls

In the preamble to the October 2015 proposed FIP,[56] the USEPA concluded that BART for NO_X from straight-grate furnaces is low-NO_X burners with water/steam injection and pre-combustion technologies. As part of the evaluation, USEPA eliminated the following emission control measures because they were technically infeasible:

- External and Induced Flue Gas Recirculation Burners due to the high oxygen content of the flue gas[57]
- Energy Efficiency Projects due to the difficulty with assigning a general potential emission reduction for this emission control measure[58]
- Selective Catalytic Reduction (SCR) controls because two vendors declined to bid on NO_x reduction testing for a taconite facility[59]

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[54] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, page 22.

[55] Ibid, page 25.

[56] Federal Register 80, No. 204 (October 22, 2015); 64168. Available at: https://www.govinfo.gov/app/details/FR-2015-10-22/2015-25023

[57] Federal Register 77, No. 158 (August 15, 2012); 49321. Available at: https://www.govinfo.gov/app/details/FR-2012-08-15/2012-19789

[58] Ibid.

[59] Ibid.

- High-stoichiometric and low-stoichiometric low NO_x burners (LNB) because the technology had never been used on straight-grate furnaces at the time of the determination.[60]

Because the technical feasibility determinations of the listed control measures have not materially changed since the 2016 final FIP, there are no "further available reasonable controls" for NO_X emissions from taconite indurating furnaces.

In accordance with the FIP, HTC implemented the BART NO_x control measures by installing and operating newly engineered site specific Low NOx Burner technology at the indurating furnace Lines 1-3 prior to the required FIP compliance dates of July 12, 2018, January 12, 2020 and July 12, 2020, respectively, and the indurating furnace Lines 1-3 are subject to the FIP NO_x emission limits[61] as shown in Table 5-1. Installation and startup of the Low NOx Burners on indurating furnace Line 3 was timely completed on April 27, 2020, prior to the indefinite idling of all 3 lines as of May 3, 2020. The indurating furnace Low NOx Burners have reduced the majority of the NOx emissions. Thus, the indurating furnace Lines 1-3 are considered "effectively controlled" sources in accordance with the 2019 Guidance and should be excluded from the requirement to prepare and submit a four-factor analysis. In addition, the BART analysis, which was finalized in 2016, already addressed the elements of the four-factor analysis, which further supports eliminating the indurating furnace Lines 1-3 from the requirement to submit a four-factor analysis[62].

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[60] Federal Register 80, No. 204 (October 22, 2015); 64167. Available at: https://www.govinfo.gov/app/details/FR-2015-10-22/2015-25023

[61] 40 CFR 52.1235(b)(1)

[62] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, Page 10.

Table 5-1 NO$_X$ Emission Limits

Unit	Unit ID	NO$_X$ Emission Limit[(1)] (lb/MMBtu)	Compliance Date[(2)]
Natural Gas Fired Indurating Furnace Line No 1 Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT Scrubbers	EQUI 95/EU 020	1.2-1.8	June 12, 2019
Natural Gas Fired Indurating Furnace Line No 2 Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT Scrubbers	EQUI 96/EU 021	1.2-1.8	December 12, 2020
Natural Gas Fired Indurating Furnace Line No 3 Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT Scrubbers	EQUI 97/EU 022	1.2-1.8	May 12, 2021

(1) In accordance with 40 CFR 52.1235(b)(1)(ii), the indurating furnace Lines 1-3 will be limited between 1.2 and 1.8 lb NOx/MMBtu beginning in the months listed above. The specific emission limit will be established by USEPA based on available NOx CEMS data from the time period when the installed emission control technology was in operation and must be submitted to USEPA for approval.

(2) The compliance date is contingent on USEPA's approval of the final emission limit.

5.2 SO$_2$ BART-required Controls

In the preamble to the August 2012 proposed FIP[63], the USEPA concluded that BART for SO$_2$ emissions from the indurating furnace Lines 1-3 at HTC is existing controls. As part of the evaluation, USEPA eliminated the following emission control measures because they were technically infeasible:

- Dry Sorbent Injection and Spray Dryer Absorption because the high moisture content of the exhaust would lead to baghouse filter cake saturation and filter plugging
- Alternative Fuels due to HTC being prohibited from burning solid fuel
- Coal drying/processing because the indurating furnace Lines 1-3 do not burn coal
- Energy Efficiency Projects due to the difficulty with assigning a general potential emission reduction for this emission control measure[64]

In addition, USEPA eliminated Wet Walled Electrostatic Precipitator (WWESP) and secondary (polishing) wet scrubber technologies because they were not cost-effective.[65] HTC also considered and eliminated

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[63] Federal Register 77, No. 158 (August 15, 2012); 49323. Available at: https://www.govinfo.gov/app/details/FR-2012-08-15/2012-19789

[64] Ibid, 49322.

[65] Ibid, 49323.

the addition of caustic, lime, or limestone to the scrubber water to improve SO_2 removal but determine it to be not practical.

Because the technical feasibility and cost effectiveness determinations of the listed control measures have not materially changed since the 2016 final FIP, there are no "further available reasonable controls" for SO_2 emissions from taconite indurating furnaces.

In accordance with the FIP, HTC has continued to operate the BART SO_2 control measures and is complying with the FIP SO_2 emission limits[66], as shown in Table 5-2. Thus, the indurating furnace Lines 1-3 are considered "effectively controlled" sources in accordance with the 2019 Guidance and can reasonably be excluded from the requirement to prepare and submit a four-factor analysis for SO_2. In addition, the BART analysis, which was finalized in 2016, already addressed the elements of the four-factor analysis, which further supports eliminating the indurating furnace Lines 1-3 from the requirement to submit a four-factor analysis[67].

Table 5-2 SO_2 Emission Limits

Unit	Unit ID	SO_2 Emission Limit$^{(1)}$ (lb/hr)	Compliance Date$^{(2)}$
Natural Gas Fired Indurating Furnace Line No 1 Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT Scrubbers	EQUI 95/EU 020	279.3	April 11, 2018
Natural Gas Fired Indurating Furnace Line No 2 Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT Scrubbers	EQUI 96/EU 021		
Natural Gas Fired Indurating Furnace Line No 3 Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT Scrubbers	EQUI 97/EU 022		

(1) This limit was established using one year of SO_2 CEMS data, in accordance with the procedures outlined within 40 CFR 52.1235(b)(2)(v).

(2) HTC submitted the revised SO_2 limit request on April 11, 2018, in accordance with 40 CFR 52.1235(b)(2)(v).

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[66] 40 CFR 52.1235(b)(2)

[67] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, Page 10.

6 Conclusion

The preceding sections of this report support the following conclusions:

- The natural gas fired indurating furnace Lines 1-3 equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT scrubbers meet the BART-required control equipment installation scenario and are "effectively controlled" sources for NO_X and SO_2 (see Section 5). As stated in the 2019 Guidance, "it may be reasonable for a state not to select an effectively controlled source."[68] Therefore, it would be reasonable and compliant with USEPA requirements to exclude HTC from further assessments of additional emission control measures.
- There has been significant progress on visibility improvement in the nearby Class I areas and MPCA's reasonable progress goals should be commensurate with this progress (see Section 3):
    - Visibility has improved at all three monitors (BOWA1, VOYA2, and ISLE1) compared to the baseline period
    - Visibility has been below the URP since 2012
    - The 2018 visibility data is below the URP for 2028
    - Additional emissions reductions have continued throughout the region and are not fully reflected in the available 5-year average (2014-2018) monitoring dataset
    - Additional emission reductions are scheduled to occur in the region prior to 2028, including ongoing transitions of area EGUs from coal to natural gas or renewable sources, as well as the installation of low-NO_X burners throughout the taconite industry
- The indurating furnace Lines 1-3 do not materially impact visibility from a theoretical (modeling) and empirical (actual visibility data) basis and should not be required to assess additional emission control measures. (see Section 4).

The combination of these factors provides sufficient justification for MPCA to justify to USEPA HTC's exclusion from the group of sources required to conduct a four-factor analysis for this implementation period. **Thus, HTC respectfully requests that the MPCA timely withdraw its request for a four-factor analysis for the natural gas fired indurating furnace Lines 1-3 already equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT scrubbers.**

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[68] Ibid, Page 22

Appendix

Appendix A

Visibility Impacts

A1 Visibility Impacts

A1.1 Trajectory Analysis

The August 2019 U.S. EPA Guidance ("2019 Guidance" or "the Guidance")[1] says that the state may use a "reasonable surrogate metrics of visibility impacts" when selecting sources to conduct an four-factor analysis and cites trajectory analysis as an example of a reasonable technique. This analysis considers reverse trajectories, as provided on MPCA's website[2], to determine the frequency that the trajectories on the "most impaired days"[3] overlapped with a specific area of influence (AOI) on the Iron Range. Data from 2011-2015 were analyzed as this was the most recent five-year period where the taconite facilities were operating under typical production rates.

A particle trajectory analysis is an analysis of the transport path of a particular air mass, including the associated particles within the air mass, to see if the air mass traveled over certain locations from specific source locations. The MPCA tracks visibility via the IMPROVE (Interagency Monitoring of Protected Visual Environments) monitoring sites at Boundary Waters Canoe Area Wilderness (BWCA), Voyageurs National Park (Voyageurs) and Isle Royale National Park (Isle Royale).[4] MPCA's website includes a tool which analyzes reverse trajectories from BWCA and Voyageurs for the "most impaired days" and the clearest days for 2007-2016 to show the regional influence on visibility. The reverse trajectories included in the MPCA tool were developed using the NOAA Hysplit model.[5] The trajectories consist of a single back trajectory for each day of interest, beginning at 18:00 and running back 48 hours with a starting height of 10 meters.

The MPCA Hysplit reverse trajectories from the "most impaired days" were analyzed to identify whether trajectories overlapped with an AOI from certain taconite facilities on the Iron Range. In order to be conservative, Barr estimated an "uncertainty region" for each trajectory based on 20% of the distance traveled for every 10km along the trajectory pathway. This method is consistent with other scientific studies analyzing reverse trajectories and trajectories associated with the NOAA Hysplit model (Stohl - 1998[6], Draxler - 1992[7], Draxler and Hess - 1998[8]). For the purpose of this analysis, the Iron Range AOI was defined as a line connecting the stack at the U. S. Steel Keetac facility with the stack at the ArcelorMittal Minorca Mine and a 3-mile radius surrounding the line. This analysis considers how often the MPCA reverse trajectories overlap the Iron Range AOI on the "most impaired days" to quantitatively determine if the emissions from the Iron Range may have been a contributor to impaired visibility. Attachment 1 to Appendix A includes tables with the annual and seasonal results of this analysis as well as two example figures showing trajectories that cross, and do not cross, the Iron Range AOI.

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[1] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[2] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Regionalinfluence

[3] "Most impaired days" is the 20% most anthropogenically impaired days on an annual basis, measured in deciviews (dv), as provided on MPCA's website.

[4] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Regionalinfluence

[5] https://www.arl.noaa.gov/hysplit/hysplit/

[6] http://www.kenrahn.com/DustClub/Articles/Stohl%201998%20Trajectories.pdf

[7] https://www.arl.noaa.gov/documents/reports/ARL%20TM-195.pdf

[8] https://www.arl.noaa.gov/documents/reports/MetMag.pdf

As shown in Figure A1 and Figure A2, reverse trajectories from BWCA and Voyageurs in 2011-2015 did not overlap the Iron Range AOI on 62-80%, and 56-71% of "most impaired days", respectively. This means the taconite industry did not influence visibility at BWCA and Voyageurs on the majority of "most impaired days" and suggest that sources other than the taconite facilities are larger contributors to visibility impairment at these sites. Furthermore, the origins of many of the "most impaired day" reverse trajectories are beyond the Iron Range AOI and thus have influences, depending on the trajectory, from other sources (e.g., Boswell Energy Center, Sherburne County Generating Station) or cities such as Duluth, St. Cloud, the Twin Cities, and Rochester as shown in Figure A3.

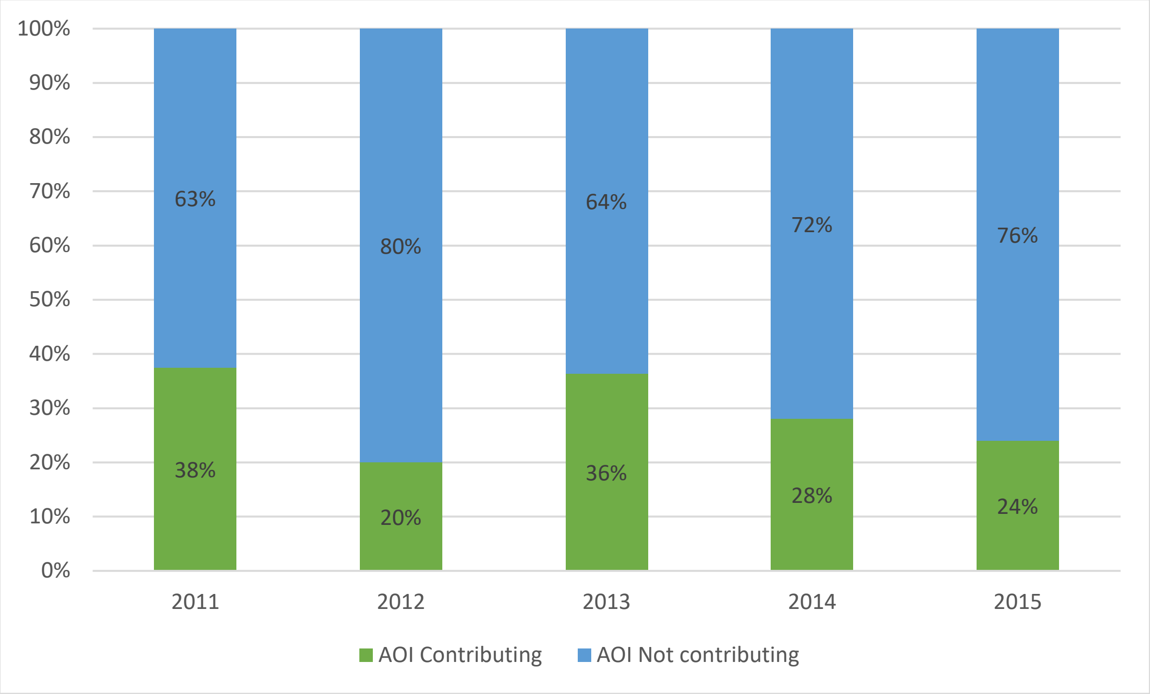

Figure A1 Proportion of "most impaired days" Iron Range AOI was Contributing or Not Contributing to Visibility at BWCA

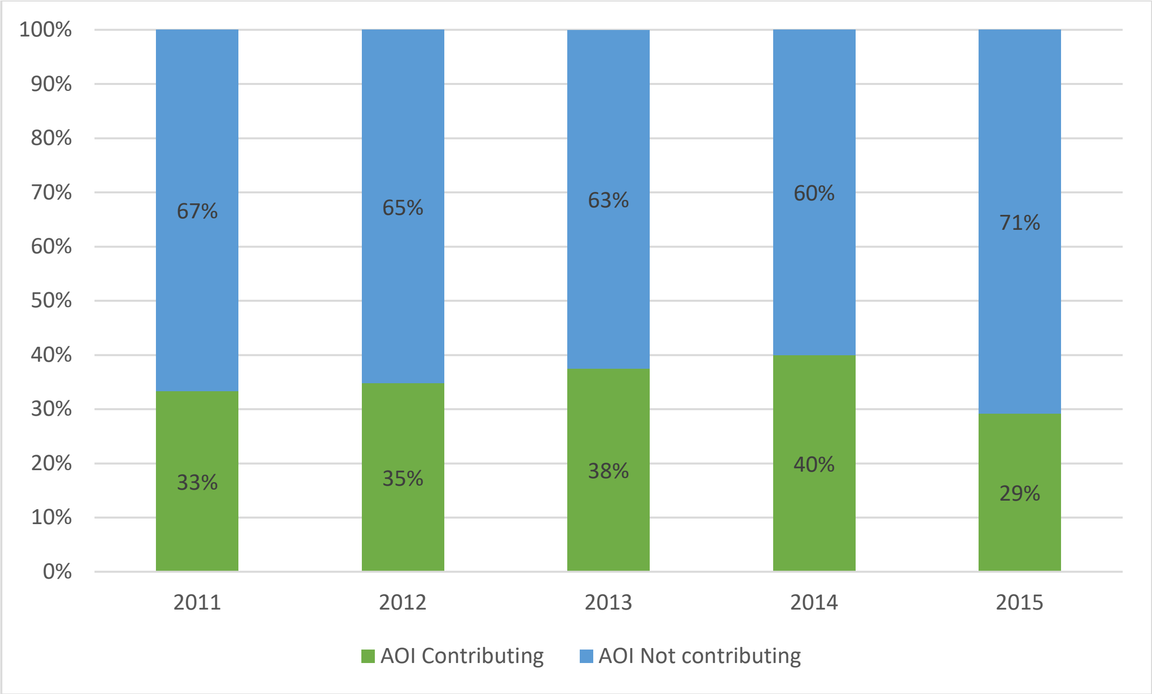

Figure A2 Proportion of "most impaired days" Iron Range AOI was Contributing or Not Contributing to Visibility at Voyageurs

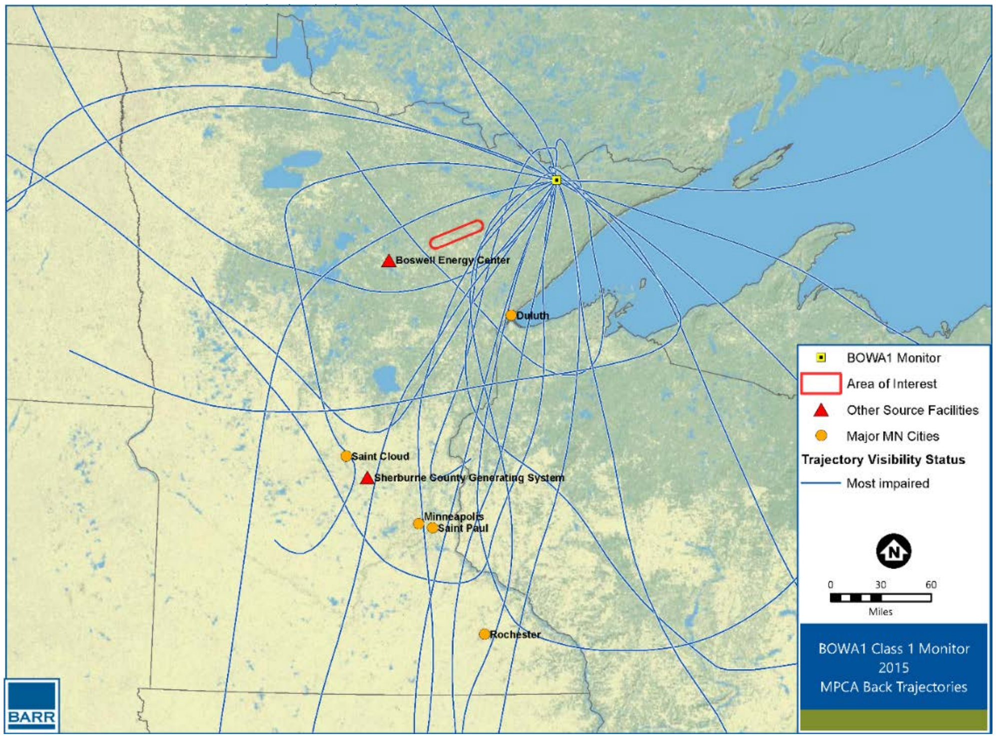

Figure A3 Reverse Trajectories and Other Sources Influencing Visibility at BWCA[9]

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[9] Source: ArcGIS 10.7.1, 2020-05-14 13:31 File: I:\Client\US_Steel\Trajectory_Analysis\Maps\Trajectory_Routes_BOWA1_2015_zoom.mxd User: ADS

A1.2 Photochemical Modeling

As part of the requirement to determine the sources to include and how to determine the potential visibility improvements to consider as part of this selection, the 2019 Guidance provided some specific guidance on the use of current and previous photochemical modeling analyses (emphasis added):

> *"A state opting to select a set of sources to analyze must reasonably choose factors and apply them in a reasonable way given the statutory requirement to make reasonable progress toward natural visibility. Factors could include but are not limited to baseline source emissions, baseline source visibility impacts (or a surrogate metric for the impacts), [and] the in-place emission control measures…"*[10]

The Guidance lists options for the evaluation of source visibility impacts from least rigorous to most rigorous as: (1) emissions divided by distance (Q/d), (2) trajectory analyses, (3) residence time analyses, and (4) photochemical modeling (zero-out and/or source apportionment). It appears that MPCA selected the least rigorous (Q/d) for inclusion of sources in the four-factor analyses. The most rigorous is described below (emphases added):

> ***"Photochemical modeling****. In addition to these non-modeling techniques, states can also use a photochemical model to quantify source or source sector visibility impacts. In 2017, EPA finalized revisions to 40 CFR Part 51 Appendix W, Guideline on Air Quality Models. As part of that action, EPA stated that photochemical grid models should be the generally preferred approach for estimating source impacts on secondary PM concentrations. The existing SIP Modeling Guidance provides recommendations on model setup, including selecting air quality models, meteorological modeling, episode selection, the size of the modeling domain, the grid size and number of vertical layers, and evaluating model performance. EPA Regional offices are available to provide an informal review of a modeling protocol before a state or multijurisdictional organization begins the modeling.*
>
> *The SIP Modeling Guidance focuses on the process for calculating RPGs using a photochemical grid model. The SIP Modeling Guidance does not specifically discuss using photochemical modeling outputs for estimating daily light extinction impacts for a single source or source sector. However, the approach on which the SIP Modeling Guidance is based can also be applied to a specific source or set of sources. The first step in doing this is to estimate the impact of the source or set of sources on daily concentrations of PM species.*
>
> *The simplest approach to quantifying daily PM species impacts with a photochemical grid model is to perform brute force "zero-out" model runs, which involves at least two model runs: one "baseline" run with all emissions and one run with emissions of the source(s) of interest removed from the baseline simulation. The difference between these simulations provides an estimate of the PM species impact of the emissions from the source(s).*

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[10] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, Page 10

> *An alternative approach to quantifying daily PM species impacts is photochemical source apportionment. Some photochemical models have been developed with a photochemical source apportionment capability, which tracks emissions from specific sources or groups of sources and/or source regions through chemical transformation, transport, and deposition processes to estimate the apportionment of predicted $PM_{2.5}$ species concentrations. Source apportionment can "tag" and track emissions sources by any combination of region and sector, or by individual source. For example, PM species impacts can be tracked from any particular source category in the U.S., or from individual states or counties. Individual point sources can also be tracked."*[11]

As part of the previous regional haze planning evaluation, and to provide comments on USEPA's disapproval of the Minnesota SIP and the subsequent Regional Haze Federal Implementation Plan (FIP) (Docket EPA-R05-OAR-2010-0954 & EPA-R05-OAR-2010-0037), Barr completed photochemical modeling of ArcelorMittal and Cleveland-Cliffs' taconite operations in 2013 using CAMx source apportionment (see Attachment 2). The basis of the CAMx modeling was the Minnesota modeling analyses, which were completed as part of the regional haze SIP, including Plume in Grid (PiG) evaluations of sources included in BART analyses. This modeling included 2002 and 2005 baseline periods with projected emissions to 2018 (the first implementation planning period for the regional haze SIPs and a strong surrogate for the baseline period for the 2nd planning period). Therefore, the analysis completed is one of the best available surrogates for the potential visibility impacts from the sources that were "tagged" as part of those comments. It is important to note that the MPCA modeling analysis did not require any additional controls for taconite sources under BART. Further, the CAMx modeling that Barr conducted showed that the impact from NO_X emissions from the Minnesota taconite facilities had very limited visibility impacts on the three Upper Midwest Class I areas.

Specifically, the results from executing CAMx concluded that the Class I areas near the Iron Range will not experience any observable visibility improvements from NO_X emission reductions that were suggested by the USEPA in the final Regional Haze FIP for taconite indurating furnaces. The modeling analysis showed that the scalar method that USEPA used to forecast the visibility improvements was inadequate to determine the visibility impacts from taconite sources. The CAMx predicted impacts for every furnace line were at or below the de minimis threshold for visibility improvement (0.1 delta-dV).

In addition, the large amount of potential NO_X emission reductions from the FIP baseline to the final FIP (>10,000 tons per year from modeled Minnesota taconite operations) was not impactful from a visibility modeling perspective. This finding provides specific source modeling evidence that additional NOx emission reductions from any or all of the taconite operations are likely not helpful for visibility improvements at the Upper Midwest Class I areas. This is particularly true given the current amount of NO_X emissions generated by the taconite sources as part of the current baseline.

The 2019 Guidance addresses how states should select sources that must conduct a four-factor analysis. The RHR suggests that states can use a photochemical model to quantify facility or even stack visibility impacts. The previous CAMx modeling was conducted for the 2018 projection year and the results are

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[11] Ibid, Page 14.

especially helpful in the current visibility impact assessment to determine if the EPA’s four-factor applicability analysis is necessary. Aside from the fact that the NO_X reductions of taconite indurating furnaces do not result in visibility improvements, the emissions from these sources have been trending downward from 2013 to present. These reductions are related to the recent installation of low NO_X burners on the taconite indurating furnaces and the overall Minnesota state reductions from the switch from coal- to natural gas-fired power plants. Thus, it is reasonable to conclude that additional emission reductions beyond the FIP limits of the taconite indurating furnaces will not be beneficial to improve visibility at the Class 1 areas nor is it anticipated to be necessary to reach the 2028 target visibility goal.

In summary, the exclusion of the taconite sources from the four factor analysis for NOx is reasonable, supported by the previous CAMx modeling performed for 2018 projected emissions that conclude additional emission reductions beyond the FIP limits of the taconite indurating furnaces will not be beneficial to improve visibility, and in line with the Guidance regarding selection of sources based on previous modeling analyses and the additional NO_X reductions anticipated in Minnesota.

A1.3 Visibility Impacts During 2009 Recession

During the economic recession in 2009, the Iron Range experienced a reduction in taconite production. This resulted in a decrease in emissions from the collective group of taconite plants and the regional power production that is needed to operate the plants. The IMPROVE monitoring data during this period was compared to monitoring data during more typical production at the taconite plants to estimate the actual (rather than modeled) impact on haze. This assessment was completed in 2012 (herein termed as “the 2012 analysis”) and submitted by Cliffs as a comment to proposed Minnesota regional haze requirements (Docket: EPA-R05-OAR-2010-0037), included as Attachment 3. The 2012 analysis focused on the likely visibility impact of NO_X emissions from the taconite indurating furnaces.

Observations noted in the 2012 analysis highlighted that concentrations of visibility impairing pollutants do not appear to closely track with actual emissions from taconite facilities. For example, nitrate (NO_3) is a component of haze associated with NO_X emissions that are emitted from a number of sources, including the indurating furnaces at the taconite facilities. As shown in Figure A4, the 2012 analysis compared taconite facility production rates to nitrate concentration for 1994-2010 at the BWCA monitor. The 2012 analysis concludes that “haze levels in BWCA did not, in general, decrease during 2009, and were therefore unaffected by emission reductions associated with the taconite production slowdown. It is noteworthy that peak events during mid-2009 in sulfate haze at BWCA when very little taconite production was occurring clearly indicate that minimal haze reduction would likely be associated with taconite plant emission reductions.”[12] The report further notes that “high nitrate haze days late in 2009 with the taconite plant curtailment that are comparable in magnitude to full taconite production periods in 2008. We also note that after the taconite plants went back to full production in 2010, the haze levels dropped, apparently due to emissions from other sources and/or states.”[13]

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[12] AECOM, “Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas,” 09/28/2012, Page 10.

[13] Ibid, Page 12.

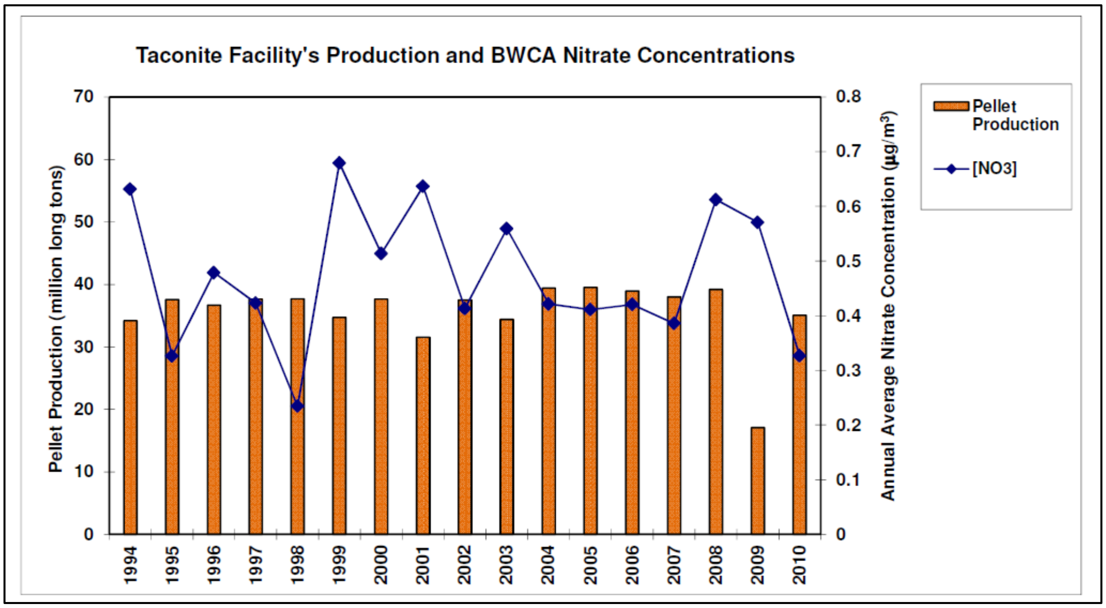

Figure A4 Minnesota Taconite Production and BWCA Nitrate Concentrations 1994-2010 [14]

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[14] AECOM, "Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas," 09/28/2012, Page 9

Attachments

Attachment 1

Trajectory Analysis Summary Tables and Reverse Trajectory Example Figures

Table A1 Results from MPCA Hysplit Trajectories for the BOWA1 Monitor

Year	Time Period	Most Impaired Days	"Most Impaired" Trajectories With Uncertainty Region Crossing Iron Range AOI (%)
2011	Winter (DJF)	9	44%
	Spring (MAM)	8	38%
	Summer (JJA)	4	0%
	Fall (SON)	3	67%
	Total	**24**	**38%**
2012	Winter (DJF)	13	23%
	Spring (MAM)	4	0%
	Summer (JJA)	1	0%
	Fall (SON)	7	29%
	Total	**25**	**20%**
2013	Winter (DJF)	9	44%
	Spring (MAM)	5	60%
	Summer (JJA)	3	0%
	Fall (SON)	5	20%
	Total	**22**	**36%**
2014	Winter (DJF)	9	33%
	Spring (MAM)	8	13%
	Summer (JJA)	2	0%
	Fall (SON)	6	50%
	Total	**25**	**28%**
2015	Winter (DJF)	13	15%
	Spring (MAM)	3	67%
	Summer (JJA)	1	0%
	Fall (SON)	8	25%
	Total	**25**	**24%**

Table A2 Results from MPCA Hysplit Trajectories for the VOYA2 Monitor

Year	Months	Most Impaired Days	"Most Impaired" Trajectories With Uncertainty Region Crossing Iron Range AOI (%)
2011	Winter (DJF)	8	38%
	Spring (MAM)	7	29%
	Summer (JJA)	4	25%
	Fall (SON)	5	40%
	Total	**24**	**33%**
2012	Winter (DJF)	13	23%
	Spring (MAM)	3	67%
	Summer (JJA)	0	0%
	Fall (SON)	7	43%
	Total	**23**	**35%**
2013	Winter (DJF)	9	22%
	Spring (MAM)	5	40%
	Summer (JJA)	3	0%
	Fall (SON)	7	71%
	Total	**24**	**38%**
2014	Winter (DJF)	10	50%
	Spring (MAM)	7	43%
	Summer (JJA)	2	0%
	Fall (SON)	6	33%
	Total	**25**	**40%**
2015	Winter (DJF)	14	21%
	Spring (MAM)	4	50%
	Summer (JJA)	1	100%
	Fall (SON)	5	20%
	Total	**24**	**29%**

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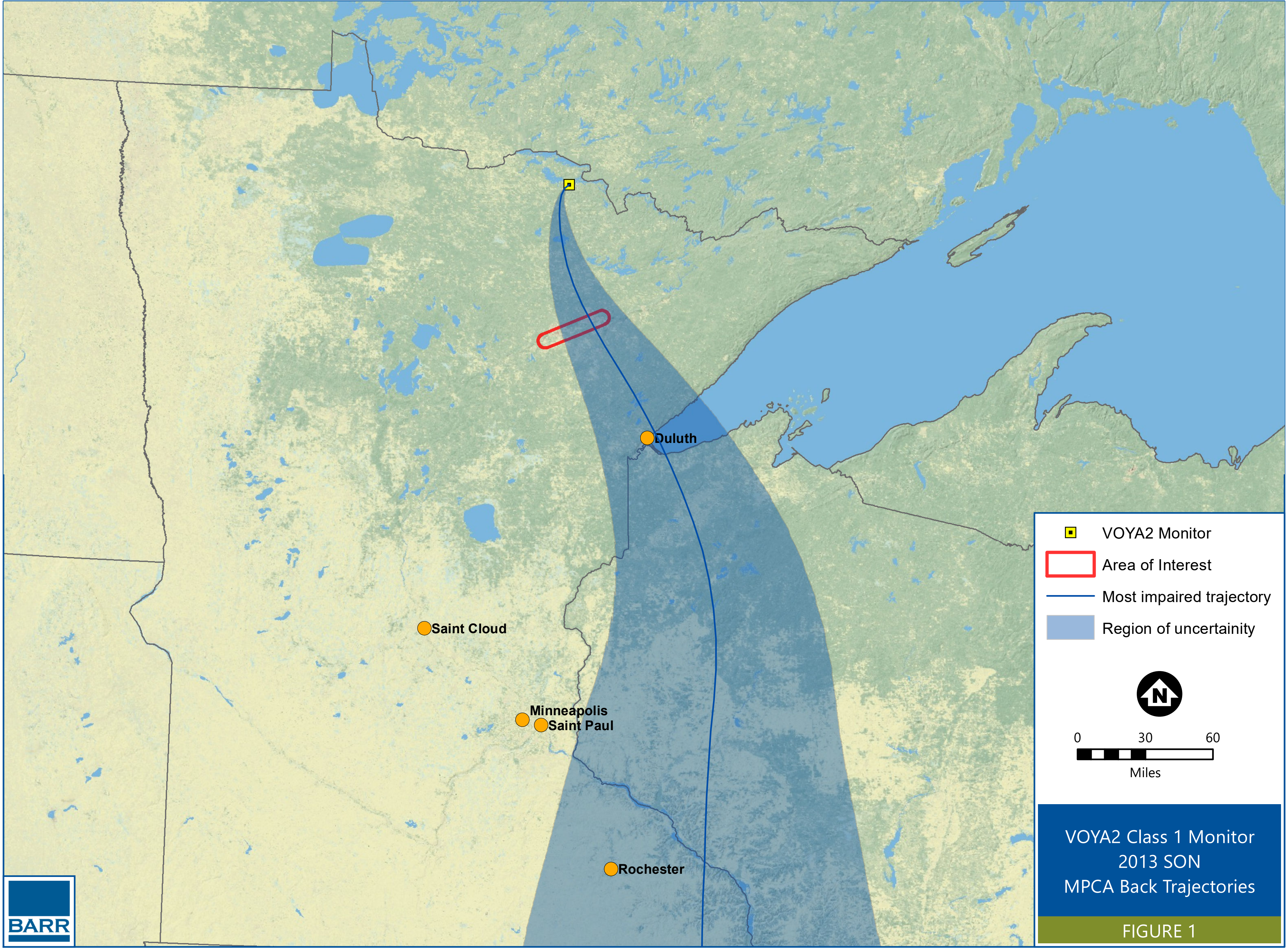
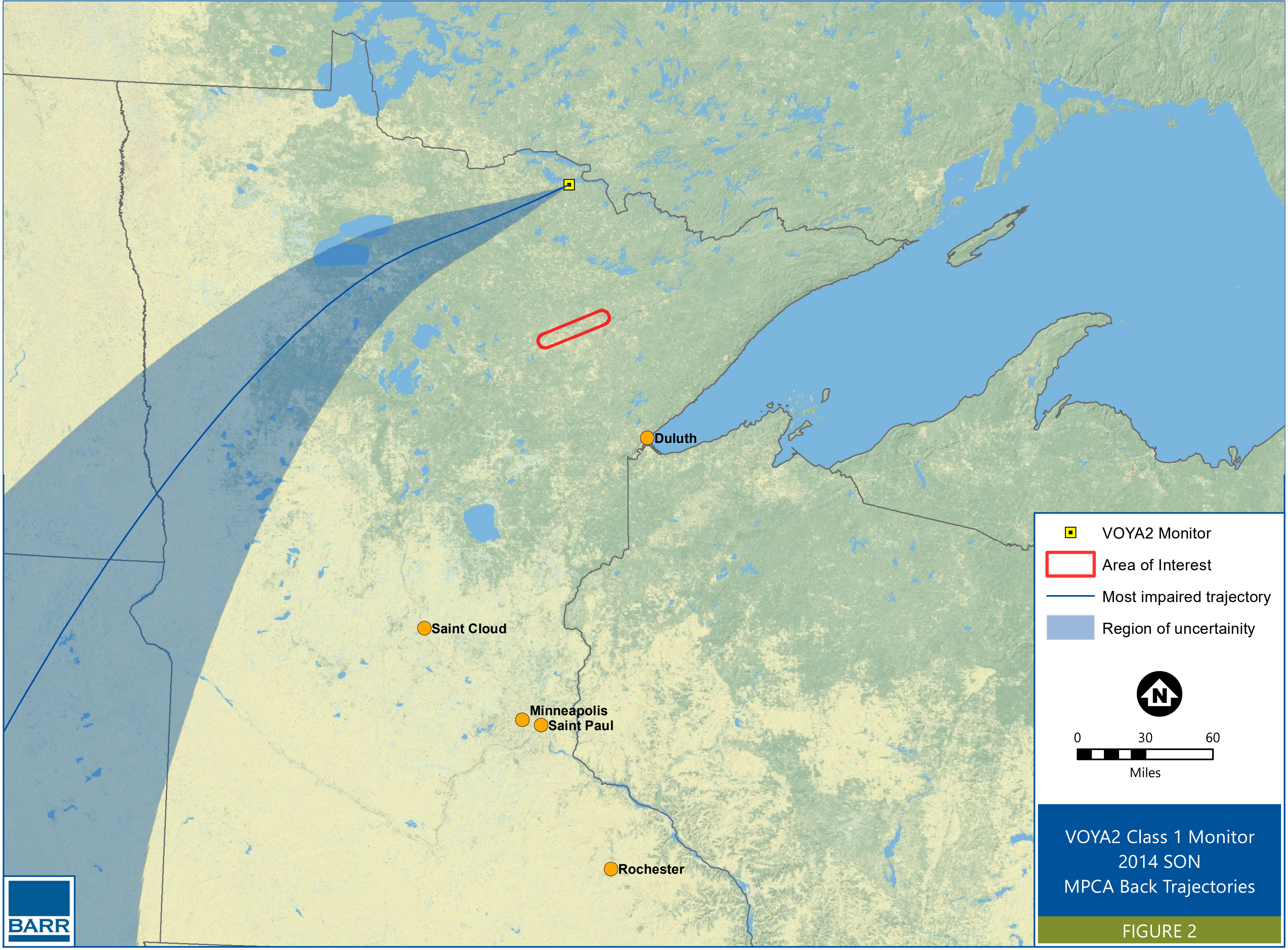


VOYA2 Class 1 Monitor
2013 SON
MPCA Back Trajectories

FIGURE 1

Barr Footer: ArcGIS 10.7.1, 2020-05-15 13:43 File: I:\Client\US_Steel\Trajectory_Analysis\Maps\Trajectory_Analysis_VOYA2_2013_SON.mxd User: ADS



VOYA2 Class 1 Monitor
2014 SON
MPCA Back Trajectories

FIGURE 2

Attachment 2

CAM_X Modeling Report

resourceful. naturally.
engineering and environmental consultants
BARR

Technical Memorandum

From: Barr Engineering
Subject: Summary of Comprehensive Air Quality Model with Extensions (CAM_X) Analyses Performed to Evaluate the EPA Regional Haze Federal Implementation Plan for Taconite Facilities
Date: March 6, 2013

Executive Summary

Barr Engineering conducted air modeling to predict the impact of NO_X reductions from certain taconite furnaces in Minnesota and Michigan. Using EPA's preferred Comprehensive Air Quality Model with Extensions (CAM_X), the model results demonstrate that the Class I areas near these furnaces will experience no perceptible visibility improvements from NO_X emission reductions envisioned by EPA in the recent Regional Haze FIP at the furnaces. The analysis strongly suggests that the scalar method that EPA used to predict visibility improvements under significant time constraints was an inadequate substitute for CAM_X, as EPA's approach over-predicted visibility impacts by factors of ten to sixty when compared with the proper CAM_X analysis. The basis for EPA's technical analysis of the visibility improvements for their proposed emission changes must therefore be dismissed as unsupportable, and the results of this analysis should be used instead. This analysis ultimately supports the conclusions of the States of Michigan and Minnesota in their Regional Haze SIPs, that experimental low NO_X burner retrofits did not meet the criteria for BART. The imperceptible visibility improvements associated with NO_X reductions from these furnaces cannot justify the cost or the operational risks of changing burners.

Discussion

This memorandum provides a summary of the methodology and results from photochemical modeling analyses conducted to support the Cliffs Natural Resources (CNR) and Arcelor Mittal (Arcelor) response to the United States Environmental Protection Agency (EPA) final Regional Haze Federal Implementation Plan (FIP) for taconite facilities. Further, it provides a basis for comment on the proposed disapproval of the Minnesota and Michigan State Implementation Plans for taconite Best Available Retrofit Technology (BART) at the above mentioned facilities. This memorandum also includes an appendix with a summary of the BART visibility improvement requirements and a review of

the EPA "scalar" method in the proposed and final FIP for determining the visibility improvement from taconite emission reductions. Further, the memorandum contrasts EPA's findings with the modeling analysis conducted and previously requested by CNR as part of its comments on the proposed FIP. The modeling evaluated emission differences at all the CNR and Arcelor taconite facilities.

Ultimately, this memorandum provides results demonstrating no perceptible visibility improvement from the NO_X emission reductions proposed and subsequently finalized by EPA in the Regional Haze FIP for the CNR and Arcelor facilities.

I. CAM_X Modeling Methodology

The methodology utilized by Barr to complete the CAM_X modeling was identical to the methods utilized by the Minnesota Pollution Control Agency (MPCA) in performing the 2002 and 2005 baseline and BART SIP modeling in 2009. This included the use of the CAM_X modeling system (CAM_X v5.01 - air quality model, MM5 - meteorological model, and EMS-2003 - emissions model) with meteorological data, low-level emission data, initial and boundary condition files, and other input files received directly from MPCA. Modifications to the emissions within the elevated point source input files used by MPCA were accomplished for the taconite facility furnace stacks to reflect the differences in the FIP baseline and final FIP control scenarios. In addition, the CAM_X run scripts used to execute the model were provided by MPCA for each of the four calendar quarters (Jan-Mar, Apr-Jun, Jul-Sep, and Oct-Dec) along with the post-processing scripts used to estimate the visibility impacts for each scenario.

An important fact is that the results from the MPCA modeling for Minnesota's regional haze State Implementation Plan (SIP) development were also utilized by EPA in the "scalar" method proposed in the FIP. These results were subsequently defended by EPA in the final FIP stating "EPA stands by the results of its ratio approach and believes that it produced reasonable results for the sources examined."[1] The methods utilized by MPCA represent not only an EPA-approved approach for SIP submittal, but also formed the basis of the visibility determinations made by EPA in the proposed and final FIP. However, since EPA did not conduct its own modeling and provided only the "scalar" results, there are substantial and inherent flaws in the EPA-estimated visibility impacts. These flaws are detailed in Appendix A to this memorandum which includes a review of the EPA scalar approach. Since the modeling reported here used identical methods to the MPCA analyses, it is consistent with the underlying data that was used in

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[1] Federal Register, Volume 78, Number 25, page 8721, February 6, 2013

the EPA FIP method for estimating visibility impact. Further, this modeling provides specific technical analyses regarding the estimated effects of CNR and Arcelor taconite unit emission reductions in the final FIP on the relevant Class I areas. To effectively evaluate the impact of NOx reductions on regional haze, this level of analyses should have been conducted by EPA before publishing and finalizing the taconite BART FIP for Minnesota and Michigan.

Nonetheless, the first step in any photochemical modeling exercise is to ensure that the modeling results can be replicated to ensure no errors in the data transfer or modeling setup. Barr worked with MPCA to obtain the 2002 and 2005 modeling input files, run scripts, and post-processing files to allow for the validation of the Barr modeling system. To be clear, the modeling comparison scenario used the exact same files provided by MPCA with no adjustments. Given the length of time required to complete the modeling analyses, this step focused on the 2002 dataset and evaluated the results from the 2002 baseline and 2002 Minnesota BART SIP. The information provided by MPCA to complete this comparison was contained in the document: “Visibility Improvement Analysis of Controls Implemented due to BART Determinations on Emission Units Subject-to-BART”, October 23, 2009. The results of the comparison are contained in Appendix B: Barr and MPCA CAM_X Modeling Comparison of Results. As expected with any photochemical model comparison running four different quarterly simulations using two different computer systems and Fortran compilers, there are insignificant differences in the end values. The overall comparison of the results was very favorable and showed excellent agreement between the four modeled datasets (i.e. 2002 baseline and 2002 BART SIP, each from MPCA and Barr).

After successful confirmation of the consistency check of the Barr modeling system to the MPCA system, the modeling focused on the specific emission changes in the MPCA elevated point source files. As with most regional modeling applications, there were 36 “core” point source files for each scenario. This set corresponds to three files per month (Saturday, Sunday, and weekday) for all twelve months. Emission information from each file was extracted for all the CNR and Arcelor taconite facilities in Minnesota to confirm the emission totals used by MPCA in the SIP baseline and BART SIP control scenarios. The emission summary data for each unit matched the summary tables within the MPCA BART SIP modeling. Also, the emission sources from Tilden Mining Company in Michigan were identified and information extracted to allow for the same type of modeling as was conducted for the Minnesota facilities.

The next step was to include United Taconite Line 1 in the baseline and FIP modeling files. Line 1 was not originally included in the MPCA modeling because it was not operational in the 2002 base year.

Therefore, the information for that source was obtained from MPCA-provided 2018 elevated point source files and incorporated into the 36 core elevated point source files. This allowed all the CNR and Arcelor furnace lines within the FIP to be evaluated as part of this modeling analysis. To that end, each CNR and Arcelor BART-eligible source was specifically identified and labeled for processing to track modeled impacts using plume-in-grid treatment and the Particulate Source Apportionment Technology (PSAT) contained within CAM_X (including Tilden Mining). A list of the sources that were included in the specific PSAT groups can be found in Appendix C: CAM_X PSAT Source List.

As part of the identification and labeling process, the MPCA BART SIP elevated point source files were converted from binary input files to ascii text files using the BIN2ASC program. (NOTE: by using the BART SIP point source files, all other Minnesota BART-eligible sources were included in this modeling exercise using their BART SIP emissions to isolate the impacts of the CNR and Arcelor units.) Then, a Fortran90 program was developed to adjust the hourly emissions from each applicable source to correspond to the sum of annual emissions within each of the following scenarios: EPA FIP baseline and EPA final FIP. It is important to note that the temporal factors for each source were not modified from the original MPCA-provided inventory files (i.e. no changes to the monthly or day-of-week factors). This emission approach allowed for the exact set of emissions within each of the scenarios to be modeled. After the emissions within the text file were adjusted, the emissions were checked for accuracy. Then, each file was converted back to binary input from ASCII text using the ASC2BIN program. The emission summary for each unit/scenario combination is contained in Appendix D: Summary of CAM_X Elevated Point Source Emissions. Appendix D also provides a reference list for the emissions from the proposed FIP, Final FIP (where applicable), and calculation methodology where EPA did not provide sufficient information to calculate emissions. Table 1 contains a facility summary for all taconite furnaces under each scenario.

As stated previously, one of the outcomes of these analyses was the comparison of EPA's scalar approach to specific photochemical modeling using EPA's emission reduction assumptions within the FIP rulemakings. These modeling analyses make no judgment as to the achievability of these emission reductions. CNR and Arcelor dispute that these NOx reductions are achievable for all furnaces. These modeling analyses are, therefore, a conservative evaluation of EPA's predicted NOx reductions – not the actual NOx reductions achievable by the application of BART.

Table 1: Facility Taconite Furnace Emission Summary

Facility	FIP Baseline (TPY)		Final FIP (TPY)		Difference (TPY)	
	SO2	NOx	SO2	NOx	SO2	NOx
Arcelor Mittal	179	3,639	179	1,092	0	2,547
Hibbing Taconite	570	6,888	570	2,066	0	4,821
United Taconite	4,043	5,330	1,969	1,599	2,074	3,731
Northshore Mining	73	764	73	229	0	535
Tilden Mining	1,153	4,613	231	1,384	922	3,229
Total	**6,018**	**21,233**	**3,022**	**6,370**	**2,996**	**14,863**

Two other issues should be noted here.

1. The first is the nested 12-km modeling domain selected by MPCA (illustrated in Figure 1) along with the specific “receptors” used for identification of the relevant Isle Royale Class I area and their use for determination of impacts from Tilden Mining Company. The Tilden Mining source was not included in the MPCA fine grid as it was not part of the Minnesota SIP. However, the elevated point source file includes the sources in the entire 36 km domain (including Tilden). As such, the Tilden emissions were available for estimation of specific visibility impacts. The receptors selected by MPCA only included the western half of the Isle Royale Class I area because that is the portion of the area closest to the Minnesota sources. However, the size of the grid cells (e.g. 12 and 36 km) provides a large number of potential receptors at all the Class I areas and little variation among receptors is expected at the distance between Tilden and Isle Royale. Thus, the modeling data should adequately represent the visibility impact at the entire Isle Royale Class I area.

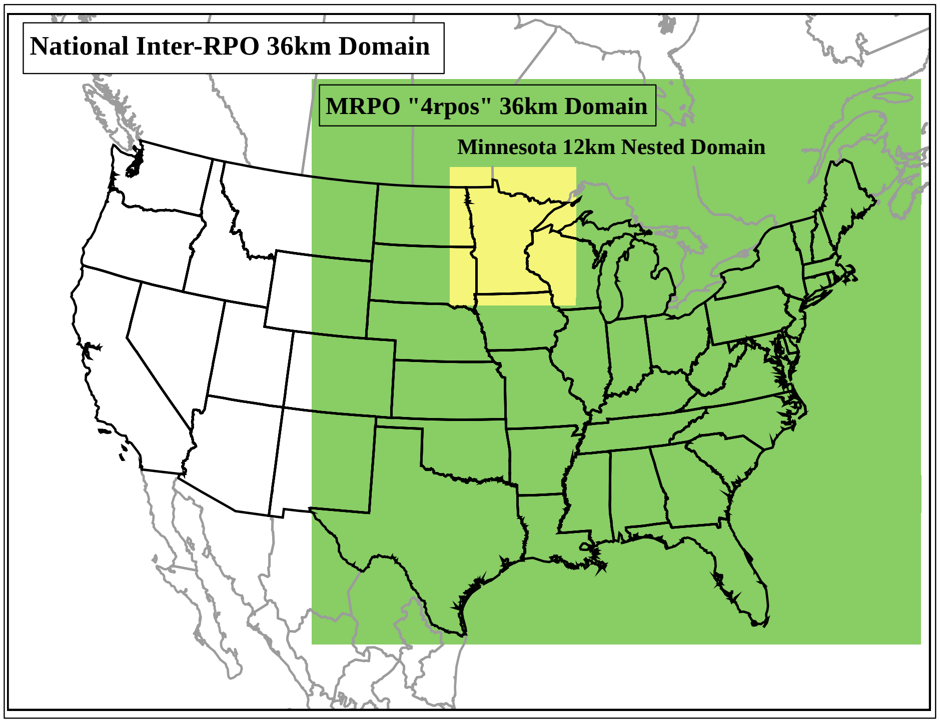

Figure 1. MPCA Modeling Domain

2. The second issue is the inconsistency between the emission reduction estimates used by EPA in the calculation of their scalar visibility benefits (i.e. Tables V-C of the proposed and final FIP) and the emission reductions calculated in the facility-specific sections of the proposed FIP. EPA's flawed calculation methodology did not use the appropriate emission reductions. In order to calculate the emissions for evaluation of the final FIP in the CAM_X modeling, Barr was left with utilizing the limited information provided in the proposed and final FIP rulemaking. The lack of information and the errors and inconsistencies within the dataset were highlighted in the information request on January 31, 2013 to EPA (included in Appendix E). As of the time of this memorandum, no response by EPA has been received by Barr. Further, given the time required to complete the modeling, assumptions were made that were conservative to calculate the FIP emissions. For example, the final FIP references a 65% NO_X reduction from Tilden Mining Company due to the switch to natural gas firing, but that was not consistent with the other gas-fired kilns (proposed FIP reduction was 70% with the same 1.2 lb NO_X/MMBTU emission limit). Therefore, to provide the maximum emission reductions, the 70% control was utilized for all the CNR and Arcelor taconite furnaces.

II. Summary of CAM_X Results

As mentioned above, the CAM_X model was executed for each calendar quarter of 2002 and 2005 using the adjusted emissions for each scenario. The results were then post-processed to calculate visibility impacts for each scenario in deciviews (dV). All these results are provided in Appendix F: CAM_X Results by Facility. For the purposes of this memorandum, the following tables compare EPA's estimates of annual average impact contained within the proposed FIP with the results generated by the CAM_X modeling for this project on a facility by facility basis. The first three facilities contain emission reductions for only NO_X: Arcelor Mittal, Hibbing Taconite, and Northshore Mining. These results are summarized in Tables 2-4. United Taconite and Tilden Mining, which have both SO_2 and NO_X emission reductions, have result comparisons that require additional discussion.

The context of these results includes the following visibility impact thresholds:

0.5 dV impact is the BART eligibility and contribute to visibility impairment threshold (i.e. if a facility has less than 0.5 dV impact in the baseline, no BART is required)[2],

1.0 dV difference is the presumed human perceptible level for visibility improvement, and

0.1 dV difference was defined by other agencies, such as the northeastern states MANE-VU Regional Planning Organization[3] as the degree of visibility improvement that is too low to justify additional emission controls. In addition, EPA's Regional Haze Rule mentions[4] that "no degradation" to visibility would be "defined as less than a 0.1 deciview increase."

The first two columns within Tables 2-4 and 6-8 provide the difference in 98th percentile visibility improvement from the baseline to the FIP control emissions, while the third column provides a measure of over-estimation when using the EPA scalar approach (i.e. % Over Estimation by EPA = EPA Estimated Difference / CAM_X Modeled Difference).

Table 2: Arcelor Mittal Visibility Impact Comparison

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[2] 40 CFR Part 51, Appendix Y – Guidelines for BART Determinations under the Regional Haze Rule.

[3] As documented by various states; see, for example, www.mass.gov/dep/air/priorities/hazebart.doc, which indicates a visibility impact of less than 0.1 delta-dv is considered "de minimis".

[4] 64 FR 35730.

Class I Area	EPA Estimated Difference 98% dV		CAM$_X$ Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	1.7		0.1		1500%
Voyageurs	0.9		0.09		1000%
Isle Royale	1.1		0.03		3700%

Table 3: Hibbing Taconite Visibility Impact Comparison

Class I Area	EPA Estimated Difference 98% dV		CAM$_X$ Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	3.2		0.19		1700%
Voyageurs	1.7		0.11		1500%
Isle Royale	2.1		0.04		5300%

Table 4: Northshore Mining Visibility Impact Comparison

Class I Area	EPA Estimated Difference 98% dV		CAM$_X$ Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	0.6		0.01		6000%
Voyageurs	0.3		0.01		3000%
Isle Royale	0.4		0.01		4000%

As pointed out in the previous comments on this proposed FIP, these results clearly demonstrate that the NOx reductions proposed in the FIP will not provide a perceptible visibility improvement. Additionally, it demonstrates that the EPA methodology using scalars severely overestimated the visibility impact from NO$_X$ emission reductions at these taconite furnaces in northeast Minnesota. Even when using maximum emission reductions from EPA's baseline, the EPA estimates grossly over predicted the potential dV improvement by over <u>10 times</u> the predicted 98th percentile visibility improvement in all cases for the Arcelor Mittal, Hibbing Taconite, and Northshore Mining facilities. The maximum 98th percentile visibility improvement predicted by the source specific tracking for any one line was 0.1 dV (Arcelor Mittal Line 1 on Boundary Waters). The minimum 98th percentile visibility improvement was 0.01 dV (Northshore Mining on Isle Royale). Further, the results presented in Table 5 for the individual furnace line impacts at Hibbing Taconite illustrate de minimis visibility improvement at all the Class I areas evaluated.

Table 5: Hibbing Taconite Line-Specific Visibility Impacts

Class I Area	Furnace Line		CAM$_X$ Modeled Difference 98% dV
Boundary Waters	Line 1		0.04
	Line 2		0.05
	Line 3		0.08
Voyageurs	Line 1		0.03
	Line 2		0.04
	Line 3		0.04
Isle Royale	Line 1		0.01
	Line 2		0.01
	Line 3		0.01

Overall, all the facilities with only NO$_X$ emission reductions predict visibility improvement from each furnace line at or below the de minimis visibility improvement threshold of 0.1 delta-dV.

Due to the sizable change in the United Taconite SO$_2$ emission reductions from the proposed FIP to the final FIP; the visibility improvement was re-calculated using EPA's apparent methodology from the proposed FIP. The EPA scalars (proposed FIP – Table V – C.9) were applied for each pollutant using the corrected emission reduction for NO$_X$ and the revised emission reduction for SO$_2$. Then, those resultants were averaged for each of the Class I areas to obtain the "updated" EPA all pollutant estimates.

Table 6: United Taconite Visibility Impact Comparison (All Pollutants)

Class I Area	Amended EPA Estimated Difference 98% dV		CAM$_X$ Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	1.6		1.40		110%
Voyageurs	0.8		0.85		N/A
Isle Royale	1.1		0.35		320%

The comparison of the total modeling effort including both pollutant reductions is surprisingly similar (except for Isle Royale). However, when the individual pollutant impacts are examined, the problem with EPA's methodology is more clearly understood. The sulfate impacts are estimated more closely to the CAM$_X$ results, while the nitrate impacts are grossly overestimated similar to the first three facilities.

The methodology used to isolate the sulfate and nitrate impacts separately from the current CAM_X results prioritizes the sulfate and nitrate impacts as part of three separate post-processing runs (all pollutants, sulfate, and nitrate). The sulfate impact was derived by sorting the visibility impacts at each receptor from each scenario by maximum sulfate contribution for each line. Likewise, the nitrate impact was derived by sorting the visibility impacts at each receptor from each scenario by maximum nitrate contribution for each line. Then, the results were summed for both lines to obtain the overall United Taconite impact by pollutant. In nearly all circumstances, this will overestimate the impact of the NO_X control. This is due to the impact from the sulfate reductions that drives the total visibility impact with a much smaller percentage from the nitrate reductions. When the nitrate impact is maximized by the sorting technique, the overall impact on the same day could be very small (e.g. nitrate = 0.1 dV; total = 0.15 dV) and would not show up as part of the overall visibility change. As detailed in the comments to the proposed FIP, it is also important to note the high probability that the maximum impacts from NO_X emission reduction occur during the winter months when Isle Royale is closed to visitors and visitation at the other Class I areas is significantly reduced from summertime maximum conditions.[5]

Table 7: United Taconite Visibility Impact Comparison (Sulfate Impact)

Class I Area	Amended EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	1.0		1.29		N/A
Voyageurs	0.5		0.74		N/A
Isle Royale	0.6		0.28		210%

Table 8: United Taconite Visibility Impact Comparison (Nitrate Impact)

Class I Area	Amended EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	2.3		0.18		1300%
Voyageurs	1.1		0.08		1400%
Isle Royale	1.6		0.05		3200%

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[5] Cliffs Natural Resources (September 28, 2012), EPA-R05-OAR-0037-0045 Att. M

In the same manner as Hibbing Taconite, United Taconite's individual furnace lines were evaluated. As mentioned in the previous paragraph, the results in Table 9 for nitrate impact are biased toward higher nitrate impacts due to the sorting of the data to maximize nitrate impact.

Table 9: United Taconite Line-Specific Nitrate Visibility Impacts

Class I Area	Furnace Line		CAM_X Modeled Difference 98% dV
Boundary Waters	Line 1		0.05
	Line 2		0.1
Voyageurs	Line 1		0.02
	Line 2		0.06
Isle Royale	Line 1		0.02
	Line 2		0.03

Nonetheless, as seen for all the other furnace lines, the results for United Taconite's predicted visibility impact are at or below the deminimis threshold for visibility improvement.

Since Tilden Mining Company was not evaluated using the same methodology as the Minnesota taconite facilities, there are no specific EPA data to compare with the CAM_X results. However, it is important to understand that the results are very similar to the other results regarding the impact of NO_X emission reductions on these Class I areas.

Table 10: Tilden Mining Visibility Impact Comparison (All Pollutants)

Class I Area	EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV
Boundary Waters	N/A		0.08
Voyageurs	N/A		0.03
Isle Royale	N/A*		0.17

*EPA estimated that the proposed FIP results in 0.501 dV visibility improvement at Isle Royale from emission reduction at Tilden Mining

Table 11: Tilden Mining Pollutant-Specific Impact Comparison

Class I Area	CAM_X Sulfate Modeled Difference 98% dV		CAM_X Nitrate Modeled Difference 98% dV
Boundary Waters	0.07		0.01
Voyageurs	0.03		0.00
Isle Royale	0.14		0.02

The visibility impacts from NO_X emission reductions at Tilden are consistent with the other modeling results and further demonstrate that significant emission reductions of NOx (3,229 tpy for Tilden) result in no visibility improvements.

III. Conclusions

Overall, the results from the three facilities with only NO_X emission reductions (Hibbing Taconite, Northshore Mining, and Arcelor Mittal) and the pollutant-specific comparisons for United Taconite and Tilden Mining illustrate that nearly 15,000 tons per year of NO_X reductions, even if they were technically and/or economically achievable, provide imperceptible visibility impacts at the Minnesota or nearby Michigan Class I areas. In all cases, the CAMx-predicted impacts for every furnace line are at or below the de minimis threshold for visibility improvement (0.1 delta-dV).

The fact that NO_X emission reductions do not provide perceptible visibility improvement was understood by MPCA when they proposed existing control and good combustion practices as BART for taconite furnaces in northeast Minnesota. This finding has been confirmed by this detailed modeling analysis. EPA, to its credit, does not claim that its scalar "ratio" approach for predicting visibility improvement is accurate. In the final FIP, EPA provided, "Therefore, even if the ratio approach was over-estimating visibility improvement by a factor of two or three, the expected benefits would still be significant."[6] Our analysis demonstrates that the ratio approach has over-estimated impacts by a factor of ten to sixty for NO_X reductions. When accurately modeled, the NO_X reductions do not yield discernible visibility benefits. To that end, the following pictures from WinHaze Level 1 Visual Air Quality Imaging Modeler

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[6] Federal Register, Volume 78, Number 25, page 8720, February 6, 2013

(version 2.9.9.1) provide a visual reference for the CAM_X predicted visibility impairment from the maximum nitrate impacting facility at Isle Royale and Boundary Waters[7].

Isle Royale FIP Base – United Taconite

Isle Royale Final FIP – United Taconite

Boundary Waters FIP Base – Hibbing Taconite

Boundary Waters Final FIP – Hibbing Taconite

Given the size of the predicted visibility impacts (both less than 0.2 dV improvement), these pictures illustrate no discernible visibility improvement from NO_X reductions at either Class I area.

Ultimately, Minnesota and Michigan reached their visibility assessments in different ways, but this modeled analysis supports their conclusion that low NO_X burner technology is not BART for the furnaces modeled at Arcelor Mittal - Minorca, Hibbing Taconite, Northshore Mining Company, United Taconite, and Tilden Mining. Therefore, EPA should approve the sections of the SIPs establishing NO_X BART on this basis.

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[7] Voyageurs National Park pictures are not contained within the WinHaze program

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APPENDIX A: Visibility Impact Requirements and EPA's Scalar Approach for Estimating Visibility Impacts within the Taconite FIP

March 6, 2013

I. Summary of Visibility Impact Requirements

The relevant language related to the specific BART visibility impact modeling approach from 40 CFR 51 Appendix Y (herein, Appendix Y), *Guidelines for BART Determinations Under the Regional Haze Rule,* is provided here, in italics with some language underlined for emphasis:

5. Step 5: How should I determine visibility impacts in the BART determination?

- *For each source, run the model, at pre-control and post-control emission rates according to the accepted methodology in the protocol.*

Use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled (for the pre-control scenario). Calculate the model results for each receptor as the change in deciviews compared against natural visibility conditions. Post-control emission rates are calculated as a percentage of pre-control emission rates. For example, if the 24-hr pre-control emission rate is 100 lb/hr of SO[2], then the post control rate is 5 lb/hr if the control efficiency being evaluated is 95 percent.

- *Make the net visibility improvement determination.*

Assess the visibility improvement based on the modeled change in visibility impacts for the pre-control and post-control emission scenarios. You have flexibility to assess visibility improvements due to BART controls by one or more methods. You may consider the frequency, magnitude, and duration components of impairment. Suggestions for making the determination are:

  - *Use of a comparison threshold, as is done for determining if BART-eligible sources should be subject to a BART determination. Comparison thresholds can be used in a number of ways in evaluating visibility improvement (e.g., the number of days or hours that the threshold was exceeded, a single threshold for determining whether a change in impacts is significant, or a threshold representing an x percent change in improvement).*
  - *Compare the 98th percent days for the pre- and post-control runs.*

Note that each of the modeling options may be supplemented with source apportionment data or source apportionment modeling.

It should be noted that Appendix Y is a guideline for state air quality agencies to proceed with modeling of BART sources. Therefore, these are not requirements, but recommended practices for evaluation of visibility impacts. Significant discretion was given to each state regarding the use of these methods. To that end, the Minnesota Pollution Control Agency applied a different modeling system than the EPA-approved model (CALPUFF) for BART evaluations. Discussed below, the new modeling system was subsequently used by EPA as part of their FIP proposal.

Further, an excerpt from the Clean Air Act, Part C, Subpart II is provided below to establish the basis for the Appendix Y regulations related to visibility improvement.

II. Summary of EPA's approach

Specific language from the proposed and final FIPs are provided in *italics* along with comments.

EPA relied on visibility improvement modeling conducted by the Minnesota Pollution Control Agency (MPCA) and recorded in MPCA's document "Visibility Improvement Analysis of Controls Due to BART Determinations on Emission Unit's Subject to BART", October 23, 2009 [attached]. The visibility improvement modeling conducted by MPCA utilized the Comprehensive Air Quality Model with Extensions (CAMx) air quality model with the Mesoscale Meteorological Model (MM5) and the Emission Modeling System (EMS-2003). Within the CAMx modeling system, MPCA used the Particulate Source Apportionment Tool (PSAT) and included evaluation of all the elevated point emissions[1] at each facility with best available retrofit technology (BART) units. The impacts from MPCA State Implementation Plan (SIP) BART controls were determined by subtracting the impact difference between the 2002/2005 base case and 2002/2005 BART control case for each facility. EPA used the impacts from four of the six facilities modeled by MPCA (Minnesota Power – Boswell Energy Center, Minnesota Power – Taconite Harbor, Northshore Mining – Silver Bay, United Taconite). The other two facilities modeled by MPCA were utility sources (Rochester Public Utilities – Silver Lake and Xcel Energy – Sherburne Generating Plant). The locations of these sources are presented below in Figure A-1 (obtained from the MPCA 2009 document).

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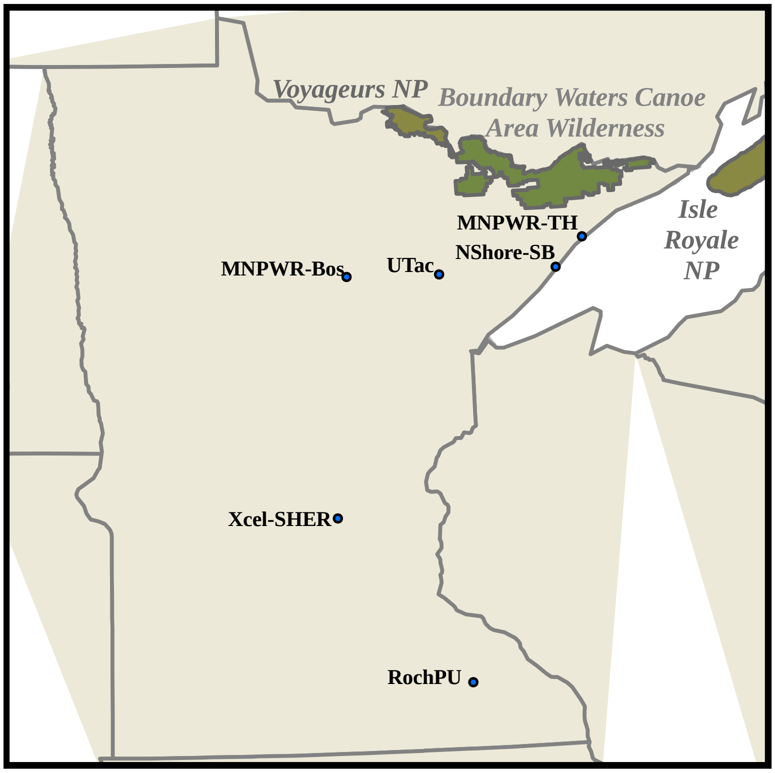
[1] Elevated point emissions include only sources with plume rise above 50m.

Figure A-1: Minnesota Facilities with BART-Determinations Assessed



In order to avoid the time and effort necessary for specific modeling of the units that EPA proposed to include in the FIP, EPA then used the average visibility impact from these four facilities to calculate two metrics for visibility improvement. The first metric is a ratio of number of days with greater than 0.5 deciview (dV) visibility divided separately by the change in SO_2 and NO_X emissions at each facility (i.e. one ratio for change in SO_2 emissions and one ratio for change in NO_X emissions). The second metric was calculated in the same fashion, but with 98th percentile visibility change divided by the change in SO_2 and NO_X emissions at each facility. These ratios were then multiplied by the estimated FIP emission reductions for the taconite facilities (including UTAC and Northshore Mining). It is important to note that there were no NO_X emission reductions modeled from any of the taconite facilities and the only source of SO_2 emission reductions from the taconite facilities was the UTAC facility.

Within the final FIP, EPA provided some additional statements that further clarified the agency's confidence regarding the use of the scalar approach for estimating visibility improvements.

III. Specific Issues Regarding EPA's Visibility Impact Estimates

Clean Air Act Section 169(A)(g)(2) – "In determining the best available retrofit technology the State (or the Administrator in determining emission limitations which reflect such technology) shall take into consideration the costs of compliance, the energy and nonair quality environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology."

Proposed FIP Page 49329 – Column 1 – "The discussion below uses MPCA's emissions data and modeled visibility impact data to derive visibility impact ratios as a function of changes in emissions of NOx and SO2 at MPCA-modeled facilities. These visibility-emission ratios were then applied to the BART-based emission changes for the source subject to this BART rule to derive possible visibility impacts."

Issues – EPA's shortcut methodology does not provide an accurate assessment of potential visibility impacts from taconite emission units subject to BART, and cannot be relied upon for several reasons stated below. The use of emission change vs. visibility impact ratios is not scientifically accurate even for a single source, much less several sources in other locations, and illustrates EPA's haste for the development of the FIP without proper modeling procedures. According to a plain language reading of the Clean Air Act section above and the best-practice recommendations within Appendix Y, the state and EPA were required to conduct a thorough evaluation of the impacts associated with the changes in emissions for each BART technology at the relevant units within each taconite facilities. EPA's methodology does not result in a thorough evaluation. If such an analysis were submitted to EPA by the state, it would be rejected as inadequate. The same should apply to EPA's analysis of the visibility improvement calculations.

MPCA used an appropriate model for estimating visibility impacts from five utility sources and one taconite source, all subject to BART, in northern Minnesota. EPA took that analyses and attempted to justify its outcomes based on its flawed methodology. Alone, the differences between the emission profiles for utility sources and taconite sources and their different locations relative to the Class I areas should preclude this type of evaluation. The difference in the emissions profile relationship between NO_X and SO_2 emissions is extremely important due to the interactive and competitive nature of the two pollutants for available ammonia (NH_3) to form ammonium nitrate or ammonium sulfate.

In addition, there are important seasonal differences in the tendency for sulfates or nitrates to be important for haze formation. Nitrates are only important in winter because significant particle formation occurs only in cold weather; oxides of nitrogen react primarily to form ozone in the summer months. On the other hand, oxidation of SO_2 to sulfate is most effective in summer with higher rates of photochemical and aqueous phase reactions. Due to the much different seasonal preferences for these two haze components, a one-size-fits-all scaling approach based upon annual averages that is insensitive to the season of the year is wholly inappropriate.

It is important to note that the only NO_X emission reductions used in the EPA scalar analyses were from utility sources. This occurred because the MPCA SIP did not include NO_X emission reductions from the United Taconite units. Therefore, the variation in emission profiles and stack parameters between utility boiler emission sources and taconite furnaces introduce another source of error with the EPA methodology.

Further, as shown in Figure A-1, the location of these sources with respect to the relevant Class I areas also causes significant problems with the EPA evaluation. The modeled visibility impacts from each source are a direct function of the wind direction. When two sources are not in the same direction with respect to the area, there is no possible way to accurately reflect the impact from the two different sources on receptor locations on any given day. For example, elevated impacts on the Voyageurs National Park from Northshore Mining would not happen on the same days as any of the other taconite sources in Minnesota.

Additionally, notwithstanding the inaccuracies of EPA's average scalar methodology, a review of the calculation of the visibility change to emission reduction ratios (i.e. MPCA-calculated visibility changes divided by SO_2 and NO_X SIP emission reductions) was conducted. This review uncovered calculation/typographical errors in the tables that were used to develop the average visibility change metrics. These simple calculation errors were subsequently corrected in the final FIP, but another inconsistency was not. The emission reductions used for NO_X within the scalar visibility calculations (Table V-C.xx) do not match the emission reduction tables in the proposed FIP (Table V – B.yy) for each facility. In one case (Northshore Mining Company), the visibility improvement reductions are greater than the baseline emissions. The attached table provides the baseline, proposed FIP, and final FIP information contained within the EPA rulemakings and docket for each taconite furnace and facility. Ultimately, even if the scalar approach used by EPA was valid, the rulemaking record is inaccurate and incomplete for the calculation of visibility impacts due to these inconsistencies.

Further, the calculation methodology for the two facilities with SO_2 and NO_X reductions (United Taconite and US Steel – Minntac) appears to utilize another invalid assumption. Also, the proposed FIP does not provide a clear explanation of the calculation of the scaled visibility impacts for these two facilities (Page 49332 – Column 1):

"To calculate the visibility impacts for the Minnesota source facilities covered by this FIP proposed rule, we multiplied the total estimated BART NOx and SO2 emission reductions for each subject facility by the appropriate visibility factor/emission change ratios in Table V-C.9 and combined the results to estimate the total visibility impacts that would result from the reduction of PM2.5 concentrations."

In Tables V-C.14 and V-C.16, the calculation of the visibility change with the two different pollutants is not explicitly provided within the FIP. Based on the use of the average visibility changes ("combined results") in the attached tables, one can generate "estimated visibility impacts" that are close to the values provided in the FIP tables. This pollutant averaging approach is not valid due to the previous comments regarding the interactive nature of the reaction mechanisms for ammonium nitrate and ammonium sulfate.

Proposed FIP Page 49331 – Column 1 – "The above visibility factor/emission change ratio data show significant variation from source-to-source and between impacted Class I areas. This variation is caused by differences in the relative location of the source (relative to the locations of the Class I areas), variations in background sources, variations in transport patterns on high haze factors, and other factors that we cannot assess without detailed modeling of the visibility impacts for the sources as a function of pollutant emission type."

Issue – EPA correctly establishes the significant variation in the ratio data and clearly distinguishes some (but not all) of the problems with the approach used to determine visibility impacts. Other problems include the differences in modeled utility source stack parameters vs. taconite stack parameters, the different inter-pollutant ratios at each facility, and the differences in visibility impacts due to on-going changes in emissions from 2002/2005 to current/future emission levels. Furthermore, EPA identifies the solution to solve this problem within their statement regarding "detailed modeling of the visibility impacts". This detailed modeling exercise was completed for BART-eligible Cliffs Natural Resources and Arcelor Mittal facilities in northeast Minnesota and Michigan to provide a clear record of the visibility improvements associated with the final FIP. This modeling demonstrates the lack of visibility improvement from nearly 15,000 tons per year of NO_X emission reductions and provides sufficient evidence to support the Minnesota and Michigan State Implementation Plans which called for good combustion practices as BART for NO_X at these facilities.

Proposed FIP Page 49333, Column 2 – "Each BART determination is a function of consideration of visibility improvement and other factors for the individual unit, but in general EPA's assessment of visibility impacts finds that technically feasible controls that are available at a reasonable cost for taconite plants can be expected to provide a visibility benefit that makes those controls warranted."

Issue – EPA's statement regarding visibility benefit from the FIP NO_X emission reductions are vastly overestimated based on updated CAM_X modeling for the Cliffs Natural Resources and Arcelor Mittal taconite furnaces. The modeling results evaluating the 98th percentile visibility improvements obtained from these emission reductions are generally less than 10% of the EPA estimates. Therefore, these NO_X controls are not warranted for visibility improvement in northeast Minnesota and Michigan.

Final FIP Page 8720, Column 2 – "EPA's analysis shows that based on all of the BART factors, including visibility, the selected controls are warranted. If highly reasonable and cost-effective controls had been available but visibility benefits were slight, EPA would have rejected those controls."

Issue – EPA describes exactly the situation with respect to "slight visibility benefits". Therefore, given the new information regarding the very slight modeled impact of NO_X emission reductions, EPA should reject those reductions as necessary under the BART program. Also, in the final FIP, EPA criticizes both MPCA and MDEQ for ignoring relevant information on Low NO_X Burner (LNB) technology. Now, given the length of time necessary and extensive effort required to generate this new visibility improvement data, EPA should reconsider its position on LNB as producing visibility benefits. This would allow EPA to support the original findings for these facilities within both the MPCA and MDEQ SIP with respect to NO_X emission limits.

Final FIP Page 8720, Column 3 – "EPA's proposed rule acknowledged the uncertainty associated with the visibility impact ratio approach, but noted that despite the uncertainties, the Agency was confident that the information was adequate to assess potential visibility improvements due to emission reductions at the specific facilities."

"Given the geographic proximity of the taconite facilities to those that were modeled, EPA believes that the ratio approach provide adequate assurance of the visibility improvements that can be expected from the proposed emission reductions."

"In the proposed rule's summary of the impacts at Boundary Waters, Voyageurs, and Isle Royale, these values ranged from 1.3 to 7.1 dVs of improvement with between 17 and 93 fewer days above the 0.5 dV threshold. Therefore, even if the ratio approach was over-estimating visibility improvements by a factor of two or three, the expected benefits would still be significant."

Final FIP Page 8721, Column 3 – "EPA stands by the results of its ratio approach and believes that it produced reasonable results for the sources examined."

Issue – EPA again chose to ignore the specific technical issues discussed above regarding the use of the ratio approach and has incorrectly assumed that this approach will provide an accurate assessment of the visibility benefits from the Cliffs and Arcelor taconite facilities. Based on the refined CAM_X modeling results using a conservative estimate of EPA's final FIP emission reduction scenario, it is obvious that the ratio approach does not provide any assurance of the visibility improvements. Further, the estimates for visibility improvement are over-estimated by between a factor of ten and sixty. Therefore, the impacts are not "significant" as referenced in EPA's response to comment within the final FIP rulemaking. The lack of technical validity contained within the EPA scalar approach is alarming. Even more alarming is the agency's refusal to conduct the type of detailed analyses necessary to allow for a technically valid answer on a rulemaking that will cost the taconite industry millions of dollars.

IV. Summary

The CAM_X modeling approach undertaken by Cliffs and Arcelor provides the best approximation of the visibility improvements from the emission reductions within the final FIP. This method replaces the use of the average ratio approach used by EPA with refined, photochemical modeling for the Cliffs and Arcelor facilities. The results of the analysis confirm the findings of the MPCA in its 2009 SIP that NO_X emission reductions do not have sufficient impact to warrant further consideration. At this point, we affirm that EPA's simple assessment is not credible, and any visibility improvement conclusions for NO_X are not technically sound. The visibility improvement results estimated by EPA using the ratio approach are between ten and sixty times greater than the results generated using the CAM_X modeling system. In essence, the modeling conducted here provides EPA another opportunity to support the findings of the MPCA and MDEQ SIPs with respect to NO_X emissions impacts at the Cliffs and Arcelor facilities.

Cliffs Natural Resources and Arcelor Mittal Taconite FIP Emission Summary

				Emissions			Emission Reductions			Emissions	
				Proposed FIP			Baseline - Prop FIP	Baseline - Prop FIP		Final FIP	
Facility	Emission Unit		Pollutant	Baseline	FIP		Emission Tables	Visibility Calcs			
	ModID	Description		tons/yr	tons/yr	Note(s)	tons/yr	tons/yr	Note(s)	lb/hr	Note(s)
Hibbing Taconite Company	{3}	Line 1	NOx	2,497	749	[1]	1,748				[4]
			SO2	202	202	[2]	0			82.6	[5]
	{4}	Line 2	NOx	2,144	643	[1]	1,500				[4]
			SO2	180	180	[2]	0			82.6	[5]
	{5}	Line 3	NOx	2,247	674	[1]	1,573				[4]
			SO2	188	188	[2]	0			82.6	[5]
	HTC	BART Units Combined	NOx	6,888	2,066		**4,821**	**5,259**	[3]		
			SO2	570	570		0	0	[3]	247.8	
Northshore Mining Company		Process Boiler 1/2	NOx	41	21	[6]	21				[10]
			SO2								
	{24}	Furnace 11	NOx	386	116	[7]	270				[11]
			SO2	38	38	[8]	0			19.5	[12]
	{25}	Furnace 12	NOx	378	113	[7]	264				[11]
			SO2	35	35	[8]	0			19.5	[12]
	NSM	BART Units Combined	NOx	805	250		**555**	**926**	[9]		
			SO2	73	73		0	0	[9]	39	
Tilden Mining Company	{1}	Boiler #1/2	NOx	79	79	[13]	0				
			SO2	0	0	[14]	0				[19]
	{3}	Ore Dryer # 1	NOx	15	15	[15]	0				
			SO2	34	34	[15]	0				[20]
	{5}	Furnace #1	NOx	4,613	1,384	[16]	3,229				[21]
			SO2	1,153	115	[17]	1,038			55	[22][23]
	TMC	BART Units Combined	NOx	4,707	1,478		3,229	3,229	[18]		
			SO2	1,187	150		1,038	1,038	[18]		
United Taconite	{26}	Line 1	NOx	**1,643**	493	[24]	1,150				[27]
			SO2	1,293	129	[25]	1,164			155	[28]
	{24}	Line 2	NOx	**3,687**	1,106	[24]	2,581				[27]
			SO2	2,750	275	[25]	2,475			374	[28]
	UTAC	BART Units Combined	NOx	5,330	1,599		**3,731**	**3,208**	[26]		
			SO2	4,043	404		3,639	3,639	[26]	529	[28]
Arcelor Mittal	ARC {12}	Line 1	NOx	3,639	1,092	[29]	**2,547**	**2,859**	[31]		[32]
			SO2	179	179	[30]	0	0	[31]	38.2	[33]

TOTAL BART UNIT	Pollutant	Baseline tons/yr	FIP tons/yr		Emission Tables tons/yr	Visibility Calcs tons/yr
TOTAL BART UNIT	NOx	21,369	6,485		14,884	15,481
	SO2	6,053	1,376		4,677	4,677

🟨	Facility BART Unit Summary or Overall Summary
🟩	FIP Baseline does not match reference
🟧	FIP Table B emission tables do not match Table C visibility calculation tables

EPA Furnace NOx Control %
70%

Notes:

[1] HTC Line 1-3 - USEPA FIP NOx Baseline Emissions Proposed FIP Table V - B.24 ; Proposed FIP NOx Emissions = 70% Control from Baseline
Typographical Error in Table V - B.24 for Line 1 Baseline Emissions (2,143.5 TPY Proposed FIP; should have been 2,497 TPY)
[2] HTC Line 1-3 - USEPA FIP SO2 Baseline Emissions from Proposed FIP Table V - B.27
[3] HTC - USEPA Proposed BART FIP Table V - C.11
[4] HTC Furnace Lines - USEPA Final BART limit of 1.5 lb NOx/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only).
[5] HTC Furnace Lines - USEPA final BART combined limit of 247.8 lb SO2/hr [82.6 lb/hr each for Lines 1 to 3] (30-day rolling avg); can be adjusted based on CEMs data.
[6] NSM Process Boilers 1&2 - NOx Emissions from Proposed FIP Table V - B.12 (p49318); LNB 50% Control from Baseline of 41.2 tons/year
[7] NSM Furnace 11/12 - NOx Emissions (Baseline and Proposed FIP Control) from Proposed FIP - Table V - B.8; FIP Emisssions = 70% Control from Baseline
[8] NSM Furnace 11/12 - No Additional SO2 Control Applied by Proposed FIP; Baseline FIP Emission Rate from Table V - B.10
[9] NSM - USEPA Proposed BART FIP Table V - C.12
[10] NSM Process Boilers 1&2 - USEPA Final BART limit of 0.085 lb NOx/MMBTU (30-day rolling average) [No additional control].
[11] NSM Furnace 11/12 - USEPA Final BART limit of 1.5 lb NOx/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only).
[12] NSM Furnace 11/12 - USEPA final BART combined limit of 39.0 lb SO2/hr (30-day rolling average); must be adjusted based on CEMs data.
[13] Tilden Process Boilers 1 & 2 - NOx Baseline Emissions Proposed FIP Table V - B.38
[14] Tilden Process Boilers 1 & 2 - SO2 Baseline Emissions Proposed FIP Table V - B.37 (0.25 TPY)
[15] Tilden Dryer #1 _ Emissions from Proposed FIP Table V - B.39 (SO2) and Table V - B.40 (NOx) - 34.07 TPY SO2, 15.1 TPY NOx
[16] Tilden Furnace 1 - NO2 Baseline and Proposed FIP Control Emissions - Proposed FIP Table V - B.34 (FIP Emissions = 70% Control from Baseline)
[17] Tilden Furnace 1 - Proposed FIP SO2 Emissions - Table V-B.36; Spray Dry Absorption 90%; Proposed FIP Text says 95% Control or 5 ppm;
Baseline Emissions Back-calculated from 90% control
[18] Tilden Furnace 1 - USEPA did not calculate visibility improvement for Tilden (Used emission difference Baseline - Proposed FIP)
[19] Tilden - USEPA Final BART limit of 1.2%S in fuel combusted by Process Boiler #1 and #2
[20] Tilden - USEPA Final BART limit of 1.5%S in fuel combusted by Ore Dryer #1
[21] Tilden Furnace 1- USEPA Final BART limit of 1.5 lb NOx/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only);
NOx emissions referenced in final FIP text as 65% control from baseline (page 8721)
[22] Tilden Furnace 1 - USEPA Final BART restriction - Only combust natural gas in Grate Kiln Line 1 with limit computed in lb SO2/hr based on CEMs;
SO2 emissions referenced in final FIP text at 80% control from baseline (page 8721)
[23] Tilden Furnace 1 - USEPA Final BART Modeling File (Part of Final Rulemaking Docket) Conducted by NPS - 55 lb/hr SO2
[24] UTAC Line 1-2 - USEPA NOx Baseline Emissions Proposed FIP Table V - B.14 ; Proposed FIP NOx Emissions = 70% Control from Baseline
[25] UTAC Line 1-2 - USEPA proposed FIP Baseline SO2 Emissions Table V - B.17; 90% Control in Table, but 95% Control within text - Proposed FIP (page 49319)
[26] UTAC - USEPA Proposed BART FIP Table V - C.13
[27] UTAC Line 1-2 - USEPA Final BART NOx Limit of 1.5 lb/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only)
[28] UTAC Line 1-2 - USEPA Final BART SO2 Limit of 529 lb/hr Combined (155 lb/hr - Line 1 & 374 lb/hr - Line 2).
[29] Arcelor - USEPA proposed FIP Baseline NOx Emissions Table V - B.19; Proposed FIP NOx Emissions = 70% Control from Baseline
[30] Arcelor - USEPA proposed FIP Baseline SO2 Emissions Table V - B.21
[31] Arcelor - USEPA Proposed BART FIP Table V - C.10
[32] Arcelor - USEPA Final BART SO2 Limit of 38.16 lb/hr for Arcelor.
[33] Arcelor - USEPA Final BART NOx Limit of 1.5 lb/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only)

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APPENDIX B: Barr and MPCA CAM_X Modeling Comparison of Results

March 6, 2013

Minnesota Power – Taconite Harbor (BART01)

MPCA
Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

PM$_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	94	90	-4	11	9	-2	30	27	-3
98th Percentile Δ dv	**2002**	9.2	8.3	-0.9	0.8	0.7	-0.1	2.2	1.9	-0.3

Barr
Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

PM$_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	95	90	-5	11	9	-2	30	27	-3
98th Percentile Δ dv	**2002**	9.14	8.25	-0.89	0.82	0.68	-0.14	2.22	1.88	-0.34

Minnesota Power – Boswell (BART04)

MPCA
Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

PM$_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Differ-Ence**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Differ-Ence**
Days > 0.5 dv	**2002**	111	60	-51	86	58	-28	48	27	-21
98th Percentile Δ dv	**2002**	4.3	2.4	-1.9	4.4	2.7	-1.8	2.0	1.0	-1.0

Barr
Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

PM$_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Differ-Ence**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	110	61	-49	86	58	-28	47	27	-20
98th Percentile Δ dv	**2002**	4.27	2.37	-1.90	4.43	2.65	-1.78	1.96	0.98	-0.98

Northshore Mining – Silver Bay (BART05)

MPCA
Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

PM$_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	77	72	-5	9	8	-1	20	15	-5
98th Percentile Δ dv	**2002**	3.96	3.79	-0.17	0.6	0.5	-0.1	0.9	0.7	-0.2

Barr
Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

PM$_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	78	72	-6	9	8	-1	20	15	-5
98th Percentile Δ dv	**2002**	3.96	3.78	-0.18	0.63	0.50	-0.13	0.90	0.73	-0.17

United Taconite (BART26)

MPCA
Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

PM$_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	59	44	-15	32	20	-12	8	1	-7
98th Percentile Δ dv	**2002**	3.0	1.7	-1.3	1.8	0.8	-0.9	0.6	0.3	-0.3

Barr
Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

PM$_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	63	46	-17	34	20	-14	8	1	-7
98th Percentile Δ dv	**2002**	3.02	1.69	-1.33	1.78	0.85	-0.93	0.59	0.28	-0.31

Xcel Sherburne (BART13)

MPCA

Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	74	58	-16	53	39	-14	42	30	-12
98th Percentile Δ dv	**2002**	2.5	1.9	-0.6	2.2	1.7	-0.5	1.4	1.0	-0.4

Barr

Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	74	59	-15	53	39	-14	42	29	-13
98th Percentile Δ dv	**2002**	2.48	1.90	-0.58	2.18	1.65	-0.53	1.44	1.06	-0.38

Rochester Public Utilities (BART07)

MPCA

Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	0	0	0	0	0	0	0	0	0
98th Percentile Δ dv	**2002**	0.1	0.1	0.0	0.1	0.0	0.0	0.1	0.0	0.0

Barr

Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	0	0	0	0	0	0	0	0	0
98th Percentile Δ dv	**2002**	0.10	0.06	0.04	0.08	0.04	0.04	0.09	0.04	0.05

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APPENDIX C: CAM$_X$ PSAT Source List

March 6, 2013

2009 MPCA Tracked, Elevated Point Sources

RANKTRAC BARTSRC_ID	RECEPTOR BARTSRC_ID	Facility ID	Facility Name [1]
1	2	2703100001	Minnesota Power - Taconite Harbor
2	3	2703700003	XCEL - Black Dog
3	4	2705300015	XCEL - Riverside
4	5	2706100004	Minnesota Power - Boswell
5	6	2707500003	Northshore Mining Co - Silver Bay
6	7	2709900001	Austin Utilities - NE Power Station
7	8	2710900011	Rochester Public Utilities
8	9	2711100002	Otter Tail Power - Hoot Lake
9	10	2712300012	XCEL - High Bridge
10	11	2713700013	Minnesota Power - Laskin
11	12	2713700027	Hibbing Public Utilities
12	13	2713700028	Virginia Dept of Public Utilities
13	14	2714100004	XCEL - Sherburne Generating Plant
14	15	2716300005	XCEL - Allen S. King
15	16	2701700002	Sappi - Cloquet
16	17	2703700011	Flint Hill Resources - Pine Bend
17	18	2706100001	Blandin Paper / Rapids Energy
18	19	2707100002	Boise Cascade - International Falls
19	20	2713700005	US Steel - Minntac
20	21	2713700015	Minnesota Power - ML Hibbard
21	22	2713700022	Duluth Steam Cooperative
22	23	2713700031	Georgia Pacific - Duluth
23	24	2713700061	Hibbing Taconite
24	25	2713700062	Arcelor Mittal
25	26	2713700063	US Steel - Keetac
26	27	2713700113	United Taconite - Fairlane Plant [2]
27	28	2700900011	International Paper - Sartell
28	29	2716300003	Marathon Ashland Petroleum
29	30	2713700083	Potlatch - Cook
30	31	2706100010	Potlatch - Grand Rapids

🟨 Included in MPCA BART SIP Modeling Report

[1] MPCA tracked all point sources on a facility-basis

[2] MPCA Emissions did not Include UTAC Line 1

2012/2013 Barr Tracked, Elevated Point Sources

Output ID	BARTSRC_ID	Facility ID	Facility / Unit Name [3]
MNPWTH	2	2703100001	Minnesota Power - Taconite Harbor
XCELBD	3	2703700003	XCEL - Black Dog
XCELRV	4	2705300015	XCEL - Riverside
MNPWBO	5	2706100004	Minnesota Power - Boswell
NSMSBU	6	2707500003	Northshore Mining Co - Silver Bay (All Other)
AUSTIN	7	2709900001	Austin Utilities - NE Power Station
ROCHPU	8	2710900011	Rochester Public Utilities
OTTRHL	9	2711100002	Otter Tail Power - Hoot Lake
XCELHB	10	2712300012	XCEL - High Bridge
MNPWLS	11	2713700013	Minnesota Power - Laskin
HIBBPU	12	2713700027	Hibbing Public Utilities
VIRGPU	13	2713700028	Virginia Dept of Public Utilities
XCELSB	14	2714100004	XCEL - Sherburne Generating Plant
XCELAK	15	2716300005	XCEL - Allen S. King
SAPPIC	16	2701700002	Sappi - Cloquet
FHRPNB	17	2703700011	Flint Hill Resources - Pine Bend
BLNPAP	18	2706100001	Blandin Paper / Rapids Energy
BOISEC	19	2707100002	Boise Cascade - International Falls
MINNTC	20	2713700005	US Steel - Minntac
MNPWHB	21	2713700015	Minnesota Power - ML Hibbard
DULSTM	22	2713700022	Duluth Steam Cooperative
GEOPAC	23	2713700031	Georgia Pacific - Duluth
HIBTAC	24	2713700061	Hibbing Taconite (All Other)
ARCELR	25	2713700062	Arcelor Mittal (All Other)
KEETAC	26	2713700063	US Steel - Keetac
UTACFP	27	2713700113	United Taconite - Fairlane Plant (All Other)
INTPAP	28	2700900011	International Paper - Sartell
MARTHN	29	2716300003	Marathon Ashland Petroleum
POTLTC	30	2713700083	Potlatch - Cook
POTLTG	31	2706100010	Potlatch - Grand Rapids
TILDEN	32	26103B4885	Tilden Mining Company (All Other)
NSMPB1	33	2707500003	Northshore Mining - Power Boiler 1
NSMPB2	34	2707500003	Northshore Mining - Power Boiler 2
NSMF11	35	2707500003	Northshore Mining - Furnace 11
NSMF12	36	2707500003	Northshore Mining - Furnace 12
UTACL1	37	2713700113	United Taconite - Line 1
UTACL2	38	2713700113	United Taconite - Line 2
ARCLN1	39	2713700062	Arcelor Mittal - Line 1
HBTCF1	40	2713700061	Hibbing Taconite - Line 1
HBTCF2	41	2713700061	Hibbing Taconite - Line 2
HBTCF3	42	2713700061	Hibbing Taconite - Line 3
TILDL1	43	26103B4885	Tilden Mining - Line 1

🟩 Included in Barr Output Evaluation

[3] Barr tracked furnace stacks and other noted stacks on a unit-basis while all other stacks were included in the "All Other" stacks

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APPENDIX D: Summary of CAM_X Elevated Point Source Emissions

March 6, 2013

Summary of CAMx Elevated Point Source Emissions

				Emissions Proposed FIP		Emissions Final FIP		Emission Reductions Baseline - Final FIP
Facility	Emission Unit ModID	Emission Unit Description	Pollutant	Baseline tons/yr	Note(s)	FIP tons/yr	Note(s)	tons/yr
Hibbing Taconite Company	{3}	Line 1	NOx	2,497	[1]	749	[3]	1,748
			SO2	202	[2]	202	[4]	0
	{4}	Line 2	NOx	2,144	[1]	643	[3]	1,500
			SO2	180	[2]	180	[4]	0
	{5}	Line 3	NOx	2,247	[1]	674	[3]	1,573
			SO2	188	[2]	188	[4]	0
	HTC	BART Furnaces Combined	NOx	6,888		2,066		4,821
			SO2	570		570		0
Northshore Mining Company		Process Boiler 1/2	NOx	41	[5]	41	[8]	0
			SO2					
	{24}	Furnace 11	NOx	386	[6]	116	[9]	270
			SO2	38	[7]	38	[10]	0
	{25}	Furnace 12	NOx	378	[6]	113	[9]	264
			SO2	35	[7]	35	[10]	0
	NSM	BART Furnaces Combined	NOx	764		229		535
			SO2	73		73		0
Tilden Mining Company	{1}	Boiler #1/2	NOx	79	[11]	79	[16]	0
			SO2	0	[12]	0	[17]	0
	{3}	Ore Dryer # 1	NOx	15	[13]	15	[18]	0
			SO2	34	[13]	34	[19]	0
	{5}	Furnace #1	NOx	4,613	[14]	1,384	[20]	3,229
			SO2	1,153	[15]	231	[21]	922
	TMC	BART Furnace	NOx	4,613		1,384		3,229
			SO2	1,153		231		922
United Taconite	{26}	Line 1	NOx	**1,643**	[22][23]	493	[26]	1,150
			SO2	1,293	[25]	577	[27]	716
	{24}	Line 2	NOx	**3,687**	[22][24]	1,106	[26]	2,581
			SO2	2,750	[25]	1,392	[27]	1,357
	UTAC	BART Furnaces Combined	NOx	5,330		1,599		3,731
			SO2	4,043		1,969		2,074
Arcelor Mittal	ARC {12}	Line 1	NOx	3,639	[28]	1,092	[30]	2,547
			SO2	179	[29]	179	[31]	0

TOTAL BART Furnaces	NOx	21,233		6,370		14,863
	SO2	6,018		3,022		2,996

🟨 Facility Furnace Unit Summary or Overall Summary
🟩 FIP Baseline does not match reference

Notes:

[1] HTC Line 1-3 - USEPA FIP NOx Baseline Emissions Proposed FIP Table V - B.24
[2] HTC Line 1-3 - USEPA FIP SO2 Baseline Emissions from Proposed FIP Table V - B.27
[3] HTC Line 1-3 - USEPA Proposed FIP NOx = 70% control from Baseline - Table V - B.24; Final FIP (1.2 or 1.5 lb/MMBTU) assumed equivalent
[4] HTC Line 1-3 - USEPA Final FIP - no additional SO2 control (Final FIP = Baseline Emissions)
[5] NSM Process Boilers 1&2 - NOx Emissions from Proposed FIP Table V - B.12 (p49318)
[6] NSM Furnace 11/12 NOx Emissions from Proposed FIP - Table V - B.8
[7] NSM Furnace 11/12 SO2 Baseline FIP Emission Rate from Proposed FIP Table V - B.10
[8] NSM Process Boilers #1 and #2 - USEPA Final BART limit of 0.085 lb NOx/MMBTU (30-day rolling average) - No additional control.
[9] NSM Furnace 11/12 - USEPA Proposed FIP NOx = 70% control from Baseline _ Table V - B.8; Final FIP (1.2 or 1.5 lb/MMBTU) assumed equivalent
[10] NSM Furnace 11/12 - no Additional SO2 Control Applied by Proposed or Final FIP (Final FIP = Baseline Emissions)
[11] Tilden Process Boilers 1 & 2 NOx Baseline Emissions Proposed FIP Table V - B.38
[12] Tilden Process Boilers 1 & 2 SO2 Baseline Emissions Proposed FIP Table V - B.37 (0.25 TPY)
[13] Tilden Dryer #1 Emissions from Proposed FIP Table V - B.39 (SO2) and Table V - B.40 (NOx) - 34.07 TPY SO2, 15.1 TPY NOx
[14] Tilden Furnace 1 NO2 Baseline - Proposed FIP Table V - B.34
[15] Tilden Furnace 1 SO2 Baseline - Proposed FIP Projected SO2 Emission Reductions - Table V-B.36; Baseline Emissions Back-calculated from 90% control
[16] Tilden Process Boilers 1 & 2 - No additional NOx control (Final FIP = Baseline Emissions)
[17] Tilden Process Boilers 1 & 2 - USEPA Final BART limit of 1.2%S in fuel - No additional SO2 control (Final FIP = Baseline Emissions)
[18] Tilden Ore Dryer #1 - No additional NOx control (Final FIP = Baseline Emissions)
[19] Tilden Ore Dryer #1 - USEPA Final BART limit of 1.5%S in fuel - No additional SO2 control (Final FIP = Baseline Emissions)
[20] Tilden Furnace 1 - USEPA Proposed FIP NOx = 70% control from Baseline _ Table V - B.34; Final FIP (1.2 or 1.5 lb/MMBTU)
NOx emissions referenced in final FIP text at 65% control from baseline (page 8721); but that is not consistent with the remaining facilities
Modeled emissions assumed 70% control to provide maximum emission reductions
[21] Tilden - USEPA Final BART restriction - Only combust natural gas in Grate Kiln Line 1 with limit computed in lb SO2/hr based on CEMs;
SO2 emissions referenced in final FIP text at 80% control from baseline (page 8721)
[22] UTAC - USEPA FIP NOx Baseline Emissions Proposed FIP Table V - B.14
[23] UTAC - Line 1 NOx Permit limit specified in permit 13700113-005 - 1,655 TPY, issued 8/19/2010, page A-49 (reference from USEPA 114 Request Question 6)
[24] UTAC - Line 2 NOx Permit limit specified in permit 13700113-005 - 3,692 TPY, issued 8/19/2010, page A-56 (reference from USEPA 114 Request Question 6)
[25] UTAC Line 1&2 - USEPA proposed FIP Baseline SO2 Emissions Table V - B.17; 90% Control in Table, 95% Control within text _ Proposed FIP (page 49319)
Modeled baseline emissions back-calculated from 90% Control; SO2 Reductions match Table V - C.13 in Proposed FIP
[26] UTAC Line 1&2 - USEAP Proposed FIP NOx = 70% Control from Baseline Table V - B.14; Final FIP (1.2 or 1.5 lb/MMBTU)
Modeled emissions assumed 70% control to provide maximum emission reductions
[27] UTAC Line 1&2 - USEPA Final BART SO2 Limit of 529 lb/hr Combined (155 lb/hr - Line 1 & 374 lb/hr - Line 2) - 30-day rolling average.
Modeled Final FIP emissions used the limits and 85% operating factor to calculate the annual emissions (designed to maximize reductions)
[28] Arcelor Line 1 - USEPA proposed FIP Baseline NOx Emissions Table V - B.19
[29] Arcelor Line 1 - USEPA proposed FIP Baseline SO2 Emissions Table V - B.21
[30] Arcelor Line 1 - Proposed FIP NOx = 70% Control from Baseline Table V - B.19; Final FIP (1.2 or 1.5 lb/MMBTU) assumed equivalent
[31] Arcelor Line 1 - USEPA Final FIP - no additional SO2 control (Final FIP = Baseline Emissions)

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APPENDIX E: Electronic Mail Requests - Proposed and Final FIP Emission Clarifications

March 6, 2013

From: Jeffry D. Bennett
Sent: Thursday, January 31, 2013 7:42 PM
To: 'Rosenthal.steven@Epa.gov'
Cc: 'Long, Michael E'
Subject: Clarification Regarding Emissions within the Final Taconite BART FIP
Attachments: EPA_FIP_Emission_Summary_01292013.xls

Steve,

Pursuant to our conversation last week regarding the baseline and controlled emission inventories within the proposed and final BART FIP for taconite furnaces, this e-mail is designed to request clarification regarding certain information contained in the rule. To that end, attached you will find a spreadsheet that summarizes and documents (to the maximum extent possible) the emission inventory data within the FIP rulemakings.

Specifically at this time, we are requesting:

(1) verification of the UTAC baseline NOx information for Line 1 and Line 2 ('Summary' Tab, Cells E30 and E32),

(2) clarification of the differences between the information contained in Columns H and I of the spreadsheet, Column H contains the difference between the FIP baseline and proposed FIP control emissions and was calculated from information within Table V-B.xx* - NOx or SO2 facility specific emission data. The Column I information contains the emission reductions obtained from Table V-C.yy visibility improvement estimate tables. For each facility, these two columns should match, but the NOx information does not. Ultimately, the bases for Table V-C.yy data is the component that is missing.

*Note: for Hibbing Taconite Line 1, a typographical error was discovered in Table V-B.24 and corrected in the spreadsheet.

(3) EPA's estimates of final FIP emissions on a tons/year basis with the corresponding emission reductions (i.e. FIP baseline – final FIP control) expected by EPA. This information would replace the "?" in Columns L and M of the spreadsheet. Along with the estimates, documentation of their bases would be extremely beneficial. For example, NOx could include either a % reduction from baseline or MMBTU/hour, Hours/year, and the appropriate lb NOx/MMBTU limit.

If you have any questions regarding these requests, feel free to contact Mike Long or myself. Thank you for your time.

Jeffry D. Bennett, PE
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JBennett@barr.com
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From: Jeffry D. Bennett
Sent: Thursday, February 14, 2013 12:02 PM
To: 'Robinson.randall@Epa.gov'
Subject: FW: Clarification Regarding Emissions within the Final Taconite BART FIP
Attachments: EPA_FIP_Emission_Summary_01292013.xls

Randy,

I talked with Steve Rosenthal yesterday about the taconite BART FIP emissions (see e-mail below). He told me that you "wrote the section on visibility improvement" and suggested I contact you about item 2 and a portion of the information requested in item 3. Barr Engineering is contracted with Cliffs Natural Resources and Arcelor Mittal to provide their taconite facilities with technical support regarding the FIP. At this point, we are trying to summarize and document the bases for the SO2 and NOx emissions that were used in the EPA baseline, the proposed FIP, and the final FIP for all their facilities.

The attached spreadsheet that I sent Steve previously includes the summary. Item 2 is related to differences between the NOx emission reductions used in the ratio visibility improvement calculations in the proposed FIP (Table V – C.yy) and the emission reductions in Table V – B.xx for each facility. Steve thought you would have the information about the basis for the Table V – C.yy reductions.

Item 3 is requesting information about the final FIP emission reductions. Specifically, you would probably have information regarding the emissions for Tilden Mining and United Taconite (UTAC) from the CALPUFF modeling completed by Trent Wickman referenced in the final FIP rulemaking docket. Please give me a call to discuss this at your earliest convenience. We are attempting to finalize the summary by COB tomorrow. Thanks for any help you can provide.

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APPENDIX F: CAMx Modeling Results by Facility

March 6, 2013

Arcelor Mittal CAMx Emissions and Modeling Results

Arcelor Emissions

Unit	EPA FIP Baseline NOx Emission (TPY) [1]	Final FIP NOx Emission (TPY) [1]	NOx Emission Difference (TPY)	EPA FIP Baseline SO2 Emission (TPY) [2]	Final FIP SO2 Emission (TPY)[3]	SO2 Emission Difference (TPY)
Line 1	3,639	1,092	2,547	179	179	0
TOTAL	**3,639**	**1,092**	**2,547**	**179**	**179**	**0**

[1] FIP Baseline and Control NOx Emissions from EPA Proposed FIP Table V-B.19 – Projected Annual NOx Emission Reductions [TPY].

[2] FIP Baseline SO2 Emissions are from EPA Proposed FIP Table V-B.21 – Annual SO2 Emissions [TPY]

[3] No SO2 emission reductions in Final FIP (i.e. EPA Baseline = Final FIP control)

Arcelor CAMx Results (By Unit) [4]

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Proposed FIP Days > 0.5 dV	Proposed FIP 98% dV	Difference Days >0.5 dV [5]	Difference 98% dV [5]
Boundary Waters						
2002						
Line #1	30	0.789	18	0.713	12	0.076
Facility Total	43	0.99	35	0.96	8	0.03
2005						
Line #1	7	0.491	3	0.326	4	0.165
Facility Total	19	0.74	8	0.55	11	0.19
Voyageurs						
2002						
Line #1	1	0.287	0	0.202	1	0.085
Facility Total	1	0.34	0	0.22	1	0.12
2005						
Line #1	0	0.182	0	0.122	0	0.060
Facility Total	0	0.22	0	0.16	0	0.06
Isle Royale						
2002						
Line #1	0	0.075	0	0.053	0	0.022
Facility Total	0	0.09	0	0.06	0	0.03
2005						
Line #1	0	0.049	0	0.033	0	0.016
Facility Total	0	0.06	0	0.04	0	0.02

[4] Visibility benchmarks:

0.5 dV impact is the BART eligibility threshold (i.e. if a facility has less than 0.5 dV impact in the baseline, no BART is required),

1.0 dV difference is the presumed human perceptible level for visibility improvement, and

0.1 dV difference was defined by other agencies as the degree of visibility improvement that is too low to justify additional emission controls. Also, EPA's Regional Haze Rule mentions that "no degradation" to visibility would be "defined as less than a 0.1 deciview increase."

[5] These two columns provide the difference in predicted days >0.5 dV and 98th percentile visibility improvement from the baseline to the FIP control emissions. The annual average number of days with > 0.5 dV improvement at all the Class I areas is considerably less than EPA's estimate (11 to 53). Also, the averages of the 98th percentile differences are **10 to 37 times less** than the predicted improvement by EPA. Note: the table below formed the basis for EPA's inclusion of control necessary at Arcelor Mittal.

Arcelor Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

(EPA Table C Emission Difference = 2,859 TPY NOx)[6]

(EPA Table B Emission Difference = 2,547 TPY NOx)[7]

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV[8]	CAMx Modeled Difference 98% dV
Boundary Waters	24	1.7		10	0.11
Voyageurs	11	0.9		1	0.09
Isle Royale	18	1.1		0	0.03

[6] Emission Difference Obtained from EPA Proposed FIP Table V-C.10 – Estimated Emission Reductions and Resulting Changes in Visibility Factors for Arcelor Mittal.

[7] Emission Difference Obtained from EPA Proposed FIP Table V-B.19.

[8] The number of days with visibility >0.5 deciviews (dV) can be a misleading indicator as illustrated by the Arcelor Mittal and Northshore Mining results (below). The 98th percentile visibility improvement at Boundary Waters during the 2002 modeled year was 0.03 dV. However, the modeling predicts this insignificant change will result in eight more days of "good visibility", defined as days with visibility at or below the 0.5 deciview threshold. Further, the Northshore Mining results at Isle Royale indicate a miniscule 0.01 deciviews, or one hundred times less than a perceptible improvement to visibility. Nonetheless, the modeling predicts this insignificant change will result in two more days of "good visibility". In both circumstances, this does not mean that the visibility change was discernible. The model gives credit for an improved day when the predicted impairment falls from 0.51 to 0.50 deciviews, but that improvement is illusory because at 0.51 deciviews people do not perceive a regional haze problem. The difference in visibility from natural background when evaluating the baseline could have several days near the 0.5 dV "contribute to visibility degradation" threshold, but well less than the 1 dV "cause visibility degradation" threshold. Then, a very small change in visibility from the baseline to the controlled emission scenario (~0.01 – 0.1 dV) could cause a large number of days to be less than the 0.5 dV benchmark without producing any real benefit to visibility.

Hibbing Taconite (HibTac) CAMx Emissions and Modeling Results

HibTac Emissions

Unit	EPA FIP Baseline NOx Emission (TPY)	Final FIP NOx Emission (TPY)	NOx Emission Difference (TPY)	EPA FIP Baseline SO2 Emission (TPY)	Final FIP SO2 Emission (TPY)	SO2 Emission Difference (TPY)
Line 1	2,497	749	1,748	202	202	0
Line 2	2,144	643	1,500	180	180	0
Line 3	2,247	674	1,573	188	188	0
TOTAL	**6,888**	**2,066**	**4,822**	**570**	**570**	**0**

HibTac CAMx Results (By Unit)

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
2002						
Line 1	1	0.337	1	0.305	0	0.032
Line 2	2	0.287	0	0.260	2	0.027
Line 3	1	0.318	0	0.245	2	0.073
Facility Total	33	1.10	22	0.96	11	0.14
2005						
Line 1	0	0.217	0	0.158	0	0.057
Line 2	0	0.203	0	0.124	0	0.079
Line 3	0	0.223	0	0.140	0	0.083
Facility Total	14	0.85	11	0.62	3	0.23
Voyageurs						
2002						
Line 1	0	0.197	0	0.168	0	0.029
Line 2	0	0.197	0	0.159	0	0.038
Line 3	0	0.211	0	0.163	0	0.048
Facility Total	18	0.67	10	0.61	8	0.06
2005						
Line 1	0	0.126	0	0.102	0	0.024
Line 2	0	0.122	0	0.085	0	0.037
Line 3	0	0.133	0	0.103	0	0.030
Facility Total	8	0.51	5	0.36	3	0.15

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Isle Royale						
2002						
Line 1	0	0.053	0	0.047	0	0.006
Line 2	0	0.045	0	0.036	0	0.009
Line 3	0	0.046	0	0.037	0	0.009
Facility Total	0	0.16	0	0.13	0	0.03
2005						
Line 1	0	0.038	0	0.027	0	0.011
Line 2	0	0.034	0	0.022	0	0.012
Line 3	0	0.037	0	0.026	0	0.011
Facility Total	0	0.13	0	0.09	0	0.04

HibTac Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

(EPA Table C Emission Difference = 5,259 TPY NOx)[8]
(EPA Table B Emission Difference = 4,822 TPY NOx)[9]

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 98% dV
Boundary Waters	44	3.2		7	0.19
Voyageurs	21	1.7		5	0.11
Isle Royale	26	2.1		0	0.04

[8] Emission Difference Obtained from EPA Proposed FIP Table V-C.11 – Estimated Emission Reductions and Resulting Changes in Visibility Factors for Hibbing Taconite.

[9] Emission Difference Obtained from EPA Proposed FIP Table V-B.24.

Northshore Mining CAMx Emissions and Modeling Results

Northshore Emissions

Unit	EPA FIP Baseline NOx Emission (TPY)	Final FIP NOx Emission (TPY)	NOx Emission Difference (TPY)	EPA FIP Baseline SO2 Emission (TPY)	Final FIP SO2 Emission (TPY)	SO2 Emission Difference (TPY)
Power Boiler #1	676	676	0	681	681	0
Power Boiler #2	1,093	1,093	0	1,098	1,098	0
Furnace 11	386	116	270	38	38	0
Furnace 12	378	113	265	35	35	0
FURNACES	**764**	**229**	**535**	**73**	**73**	**0**
TOTAL	**2,533**	**1,998**	**535**	**1,852**	**1,852**	**0**

Northshore CAMx Results (By Unit)

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
2002						
Power Boiler #1	32	1.487	32	1.499	0	-0.012
Power Boiler #2	49	2.087	49	2.097	0	-0.010
Furnace 11	0	0.136	0	0.139	0	-0.003
Furnace 12	0	0.133	0	0.122	0	0.011
Facility Total	73	4.16	72	4.14	1	0.02
2005						
Power Boiler #1	13	0.640	13	0.654	0	-0.014
Power Boiler #2	22	0.926	23	0.911	0	0.015
Furnace 11	0	0.087	0	0.067	0	0.020
Furnace 12	0	0.082	0	0.076	0	0.006
Facility Total	51	1.67	50	1.68	1	-0.01
Voyageurs						
2002						
Power Boiler #1	1	0.196	1	0.196	0	0.000
Power Boiler #2	1	0.293	1	0.293	0	0.000
Furnace 11	0	0.016	0	0.013	0	0.003
Furnace 12	0	0.015	0	0.013	0	0.002
Facility Total	8	0.51	8	0.51	0	0.00

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Voyageurs						
2005						
Power Boiler #1	0	0.188	0	0.193	0	-0.005
Power Boiler #2	1	0.244	1	0.247	0	-0.003
Furnace 11	0	0.020	0	0.018	0	0.002
Furnace 12	0	0.021	0	0.016	0	0.004
Facility Total	6	0.47	6	0.46	0	0.01
Isle Royale						
2002						
Power Boiler #1	3	0.294	3	0.294	0	0.000
Power Boiler #2	6	0.412	6	0.408	0	0.004
Furnace 11	0	0.034	0	0.028	0	0.006
Furnace 12	0	0.037	0	0.029	0	0.008
Facility Total	16	0.75	15	0.74	1	0.00
2005						
Power Boiler #1	3	0.180	3	0.180	0	0.000
Power Boiler #2	4	0.320	4	0.322	0	-0.002
Furnace 11	0	0.036	0	0.023	0	0.013
Furnace 12	0	0.034	0	0.022	0	0.012
Facility Total	10	0.57	8	0.55	2	0.02

Northshore Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

(EPA Table C Emission Difference = 926 TPY NOx)[10]

(EPA Table B Emission Difference = 535 TPY NOx)[11]

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 98% dV
Boundary Waters	8	0.6		1	0.01
Voyageurs	4	0.3		0	0.01
Isle Royale	5	0.4		2	0.01

[10]Emission Difference Obtained from EPA Proposed FIP Table V-C.12 – Estimated Emission Reductions and Resulting Changes in Visibility Factors for Northshore Mining.

[11]Emission Difference Obtained from EPA Proposed FIP Table V-B.8; further the emission reductions in Table C exceed the FIP baseline in Table B by 142 TPY.

United Taconite (UTAC) CAMx Emissions and Modeling Results

UTAC Emissions

Unit	EPA FIP Baseline NOx Emission (TPY)	Final FIP NOx Emission (TPY)	NOx Emission Difference (TPY)[12]	EPA FIP Baseline SO2 Emission (TPY)	Final FIP SO2 Emission (TPY)[13]	SO2 Emission Difference (TPY)
Line 1	1,643	493	1,150	1,293	577	716
Line 2	3,687	1,106	2,581	2,750	1,392	1,358
TOTAL	**5,330**	**1,599**	**3,731**	**4,043**	**1,969**	**2,074**

[12]NOx emission difference was calculated using 70% emission reduction from EPA Baseline within the proposed FIP (corresponding to 1.2 lb NOx/MMBTU); to ensure maximum emission reductions were evaluated there was no change to the final FIP emissions to reflect the final FIP limit of 1.5 lb NOx/MMBTU.

[13]Final FIP SO2 Emissions were calculated using the final FIP limit of 529 lb/hr with an operating factor of 85%; this was done to maximize the emission reductions while using a reasonable operating factor

UTAC CAMx Results (By Unit)

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
2002						
Line #1	22	1.294	10	0.674	12	0.620
Line #2	45	2.744	30	1.556	15	1.189
Facility Total	76	4.22	55	2.37	21	1.85
2005						
Line #1	11	0.610	2	0.303	9	0.307
Line #2	26	1.294	15	0.678	11	0.616
Facility Total	52	2.52	34	1.57	18	0.95
Voyageurs						
2002						
Line #1	12	0.606	2	0.307	10	0.299
Line #2	26	1.452	15	0.771	11	0.681
Facility Total	42	2.10	26	1.11	16	0.99
2005						
Line #1	4	0.331	1	0.181	3	0.150
Line #2	17	0.786	6	0.446	11	0.340
Facility Total	33	1.47	14	0.76	19	0.71

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Isle Royale						
2002						
Line #1	0	0.255	0	0.117	0	0.138
Line #2	8	0.518	0	0.266	8	0.252
Facility Total	13	0.81	3	0.41	10	0.40
2005						
Line #1	0	0.163	0	0.080	0	0.083
Line #2	1	0.322	0	0.184	1	0.138
Facility Total	10	0.57	0	0.28	10	0.29

UTAC Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

(EPA Table C Emission Difference = 3,208 TPY NOx and 3,639 TPY SO2)[14]
(EPA Table B Emission Difference = 3,731 TPY NOx and 3,639 TPY SO2)[15]

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV[16]	CAMx Modeled Difference 98% dV[16]
Boundary Waters	29	1.9		20	1.40
Voyageurs	12	0.99		18	0.85
Isle Royale	14	1.16		10	0.35

[14]Emission Difference Obtained from EPA Proposed FIP Table V-C.13 – Estimated Emission Reductions and Resulting Changes in Visibility Factors for United Taconite.

[15]Emission Difference Obtained from EPA Proposed FIP Table V-B.14 (SO2) and V-B.17 (NOx) – NOx reductions are not consistent

[16]Baseline – final FIP Emission Reductions -> 3,731 TPY NOx and 2,074 TPY SO2

The United Taconite comparison table above does not provide an "apples to apples" comparison. As noted, the EPA estimated visibility benefits include more SO2 emission reductions (proposed FIP) than are included in the final FIP. This table was amended to include the revised SO2 emission reductions using EPA's apparent methodology within the proposed FIP. The EPA scalars (proposed FIP – Table V – C.9) were applied for each pollutant using the corrected emission reduction for NOx and the revised emission reduction for SO2. Then, those resultants were averaged for each of the Class I areas to obtain the amended EPA estimates below to provide for the appropriate comparison of EPA's method.

Amended UTAC Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

Final FIP Emission Difference = 3,731 TPY NOx and 2,074 TPY SO2

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 98% dV
Boundary Waters	22	1.6		20	1.40
Voyageurs	10	0.8		18	0.85
Isle Royale	14	1.1		10	0.35

As discussed above, the SO4 and NO3 visibility benefits were combined by EPA. The following tables provide a modeled comparison of the impacts sorted by SO4 and NO3 on a line-specific basis, then combined for both lines. The sulfate impact was derived by sorting the visibility impacts at each receptor from each scenario by maximum sulfate contribution for each line. Likewise, the nitrate impact was derived by sorting the visibility impacts at each receptor from each scenario by maximum nitrate contribution for each line. Then, the results were summed for both lines to obtain the overall UTAC impact by pollutant. In nearly all circumstances, this will overestimate the impact of the NO_X control. This is due to the impact from the sulfate reductions that drives the total visibility impact with a much smaller percentage from the nitrate reductions. When the nitrate impact is maximized by the sorting technique, the overall impact on the same day could be very small (e.g. nitrate = 0.15 dV; total = 0.20 dV) and would not show up as part of the overall visibility change (see Line 2 – 2002 Boundary Waters results).

UTAC Line 1 – Pollutant Specific Modeling Results

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
2002						
Line #1 – NO3	0	0.106	0	0.059	0	0.047
Line #1 – SO4	22	1.294	10	0.674	12	0.620
Line #1 – All	22	1.294	10	0.674	12	0.620
2005						
Line #1 – NO3	0	0.136	0	0.083	0	0.053
Line #1 – SO4	8	0.571	2	0.280	6	0.291
Line #1 – All	11	0.610	2	0.303	9	0.307
Voyageurs						
2002						
Line #1 – NO3	0	0.040	0	0.017	0	0.023
Line #1 – SO4	11	0.582	2	0.301	9	0.281
Line #1 – All	12	0.606	2	0.307	10	0.299
2005						
Line #1 – NO3	0	0.048	0	0.027	0	0.021
Line #1 – SO4	4	0.330	1	0.155	3	0.175
Line #1 – All	4	0.331	1	0.181	3	0.150
Isle Royale						
2002						
Line #1 – NO3	0	0.033	0	0.015	0	0.018
Line #1 – SO4	0	0.216	0	0.104	0	0.112
Line #1 – All	0	0.255	0	0.117	0	0.138
2005						
Line #1 – NO3	0	0.026	0	0.011	0	0.015
Line #1 – SO4	0	0.150	0	0.072	0	0.078
Line #1 – All	0	0.163	0	0.080	0	0.083

UTAC Line 2 – Pollutant Specific Modeling Results

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
2002						
Line #2 – NO3	1	0.237	0	0.090	1	0.147
Line #2 – SO4	44	2.679	28	1.547	16	1.132
Line #2 – All	45	2.744	30	1.556	15	1.189
2005						
Line #2 – NO3	1	0.195	0	0.091	1	0.104
Line #2 – SO4	25	1.196	15	0.659	10	0.539
Line #2 – All	26	1.294	15	0.678	11	0.616
Voyageurs						
2002						
Line #2 – NO3	0	0.104	0	0.031	0	0.073
Line #2 – SO4	25	1.446	15	0.768	10	0.678
Line #2 – All	26	1.452	15	0.771	11	0.681
2005						
Line #2 – NO3	0	0.083	0	0.033	0	0.050
Line #2 – SO4	16	0.773	6	0.436	10	0.337
Line #2 – All	17	0.786	6	0.446	11	0.340
Isle Royale						
2002						
Line #2 – NO3	0	0.054	0	0.018	0	0.036
Line #2 – SO4	7	0.469	0	0.245	7	0.224
Line #2 – All	8	0.518	0	0.266	8	0.252
2005						
Line #2 – NO3	0	0.046	0	0.016	0	0.030
Line #2 – SO4	1	0.319	0	0.166	1	0.153
Line #2 – All	1	0.322	0	0.184	1	0.138

UTAC Comparison of Sulfate-Specific Amended EPA Final FIP Visibility Improvement Estimates with CAMx Modeling Analyses

Final FIP Emission Difference = 2,074 TPY SO2

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 98% dV
Boundary Waters	14	1.0		22	1.29
Voyageurs	6	0.5		16	0.74
Isle Royale	8	0.6		4	0.28

UTAC Comparison of Nitrate-Specific Amended EPA Final FIP Visibility Improvement Estimates with CAMx Modeling Analyses

Final FIP Emission Difference = 3,731 TPY NOx

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 98% dV
Boundary Waters	31	2.3		1	0.18
Voyageurs	15	1.1		0	0.08
Isle Royale	20	1.6		0	0.05

The maximum 98th percentile NO3 impact when combining both line emission reductions is 0.18 dV, while the maximum 98th percentile SO4 impact for both lines is 1.29 dV. Based on these results, it is evident that the SO4 impact on the Class I areas provides the vast majority of the predicted CAMx estimates of visibility improvement. This finding is consistent with MPCA's original finding for BART in the 2009 SIP that NOx emission reductions do not provide substantive visibility improvement.

Tilden Mining CAMx Emissions and Modeling Results

Tilden Emissions

Unit	EPA FIP Baseline NOx Emission (TPY)	Final FIP NOx Emission (TPY)	NOx Emission Difference (TPY)	EPA FIP Baseline SO2 Emission (TPY)	Final FIP SO2 Emission (TPY)	SO2 Emission Difference (TPY)
Line 1	4,613	1,384	3,229	1,153	231	922
TOTAL	**4,613**	**1,384**	**3,229**	**1,153**	**231**	**922**

Tilden CAMx Results (By Unit)

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
2002						
Line #1	0	0.141	0	0.037	0	0.104
2005						
Line #1	0	0.097	0	0.042	0	0.055
Voyageurs						
2002						
Line #1	0	0.042	0	0.011	0	0.031
2005						
Line #1	0	0.041	0	0.010	0	0.031
Isle Royale						
2002						
Line #1	1	0.300	0	0.094	1	0.206
2005						
Line #1	0	0.211	0	0.070	0	0.141

Tilden Line 1 – Pollutant Specific Modeling Results

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
2002						
Line #1 – NO3	0	0.031	0	0.013	0	0.018
Line #1 – SO4	0	0.102	0	0.022	0	0.080
Line #1 – All	0	0.141	0	0.037	0	0.104
2005						
Line #1 – NO3	0	0.045	0	0.042	0	0.003
Line #1 – SO4	0	0.087	0	0.019	0	0.068
Line #1 – All	0	0.097	0	0.042	0	0.055
Voyageurs						
2002						
Line #1 – NO3	0	0.002	0	0.001	0	0.001
Line #1 – SO4	0	0.041	0	0.011	0	0.030
Line #1 – All	0	0.042	0	0.011	0	0.031
2005						
Line #1 – NO3	0	0.005	0	0.003	0	0.002
Line #1 – SO4	0	0.039	0	0.008	0	0.031
Line #1 – All	0	0.041	0	0.010	0	0.031
Isle Royale						
2002						
Line #1 – NO3	0	0.084	0	0.038	0	0.046
Line #1 – SO4	1	0.197	0	0.052	1	0.145
Line #1 – All	1	0.300	0	0.094	1	0.206
2005						
Line #1 – NO3	0	0.043	0	0.047	0	-0.004
Line #1 – SO4	0	0.176	0	0.040	0	0.136
Line #1 – All	0	0.211	0	0.070	0	0.141

Attachment 3

2012 AECOM Report

AECOM

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

Robert Paine and David Heinold, AECOM

September 28, 2012

Executive Summary

This report reviews several aspects of the visibility assessment that is part of any Best Available Retrofit Technology (BART) assessment. The crux of this analysis focuses upon two opportunistic emission reductions that have resulted in no perceptible visibility benefits, while a straightforward application of EPA's modeling procedures would predict a substantial visibility benefit. These actual emission reduction cases include the shutdown of the Mohave Generating Station (and minimal visibility effects at the Grand Canyon) as well as the economic slowdown that affected emissions from the taconite plants in Minnesota in 2009.

There are several reasons why there is an inconsistency between the real world and the modeling results:

- Natural background conditions, which are used in the calculation of haze impacts due to anthropogenic emissions, are mischaracterized as too clean, which exaggerates the impact of emission sources. Overly clean natural conditions can erroneously indicate that some states are missing the 2018 milestone for achieving progress toward an impossible goal by the year 2064.

- The chemistry in the current EPA-approved version of CALPUFF as well as regional photochemical models overestimates winter nitrate haze, especially with the use of high ammonia background concentrations. There are other CALPUFF features that result in overpredictions of all pollutant concentrations that are detailed in this report. Therefore, BART emission reductions will be credited with visibility modeling for more visibility improvements than will really occur. We recommend that EPA adopt CALPUFF v. 6.42, which includes substantial improvements in the chemistry formulation. We also recommend the use of seasonally varying ammonia background concentrations, in line with observations and the current capabilities of CALPUFF.

- In addition to CALPUFF, the use of regional photochemical models results in significant nitrate haze overpredictions for Minnesota Class I area predictions.

- The modeled base case modeled scenario is always a worst-case emission rate which is assumed to occur every day. The actual emissions are often lower, and so the modeled improvement is an overestimate.

Impacts of the taconite plants' NO_X emissions are confined to winter months by the unique chemistry for nitrate particle formation. During these months, the attendance at the parks is greatly reduced by the closure of significant portions of the parks and the inability to conduct boating activities on frozen water bodies. In the case of Isle Royale National Park, there is total closure in the winter, lasting for 5 ½ months. The BART rule makes a provision for the consideration of such seasonal impacts. The imposition of NO_X controls year-round would not only have minimal benefits in the peak visitation season of summer, but also could lead to increases in haze due to the increased power requirements (and associated emissions) needed for their operation, an effect that has not been considered in the visibility modeling.

An analysis of the impact of the visibility impacts of Minnesota BART sources on Michigan's Class I areas, as well as the impacts of Michigan sources on Minnesota's Class I areas indicates that the effects on the other state's Class I areas is minor. The taconite plant emissions are not expected to interfere with the ability of other states to achieve their required progress under the Regional Haze Rule.

Introduction

Best Available Retrofit Technology (BART) is part of the Clean Air Act (Appendix Y of 40 CFR Part 51) as a requirement related to visibility and the 1999 Regional Haze Rule (RHR)[1] that applies to existing stationary sources. Sources eligible for BART were those from 26 source categories with a potential to emit over 250 tons per year of any air pollutant, and that were placed into operation between August 1962 and August 1977. Final BART implementation guidance for regional haze was published in the Federal Register on July 6, 2005[2].

The United States Environmental Protection Agency (EPA) has issued a proposed rule[3] to address BART requirements for taconite plants in Minnesota and Michigan that involves emission controls for SO_2 and NO_X. This document addresses the likely visibility impact of taconite plant emissions, specifically NO_X emissions, for impacts at Prevention of Significant Deterioration (PSD) Class I areas that the RHR addresses.

Locations of Emission Sources and PSD Class I Areas

Figure 1 shows the location of BART-eligible taconite plants in Minnesota and Michigan addressed in EPA's proposed rule, as well as Class I areas within 500 km of these sources. In most applications of EPA's preferred dispersion model for visibility impacts, CALPUFF[4], the distance limitation is 200-300 km because of the overprediction tendencies[5] for further distances. The overprediction occurs because of extended travel times that often involve at least a full day, during which there can be significant wind shear influences on plume spreading that the model and the meteorological wind field does not accommodate. With larger travel distances, there are higher uncertainties in the predictions of any model, either CALPUFF or a regional photochemical model. Therefore, a reasonable upper limit for establishing the impact of the taconite sources would be 500 km, with questionable results beyond 200-300 km from the source. In this case, the Class I areas involved are those shown in Figure 1. All other PSD Class I areas are much further away. It is noteworthy that EPA's visibility improvement assessment considered only three Class I areas: Voyageurs National Park, Boundary Waters Canoe Area Wilderness, and Isle Royale National Park.

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[1] Regional Haze Regulations; Final Rule. *Federal Register*, *64*, 35713-35774. (July 1, 1999).

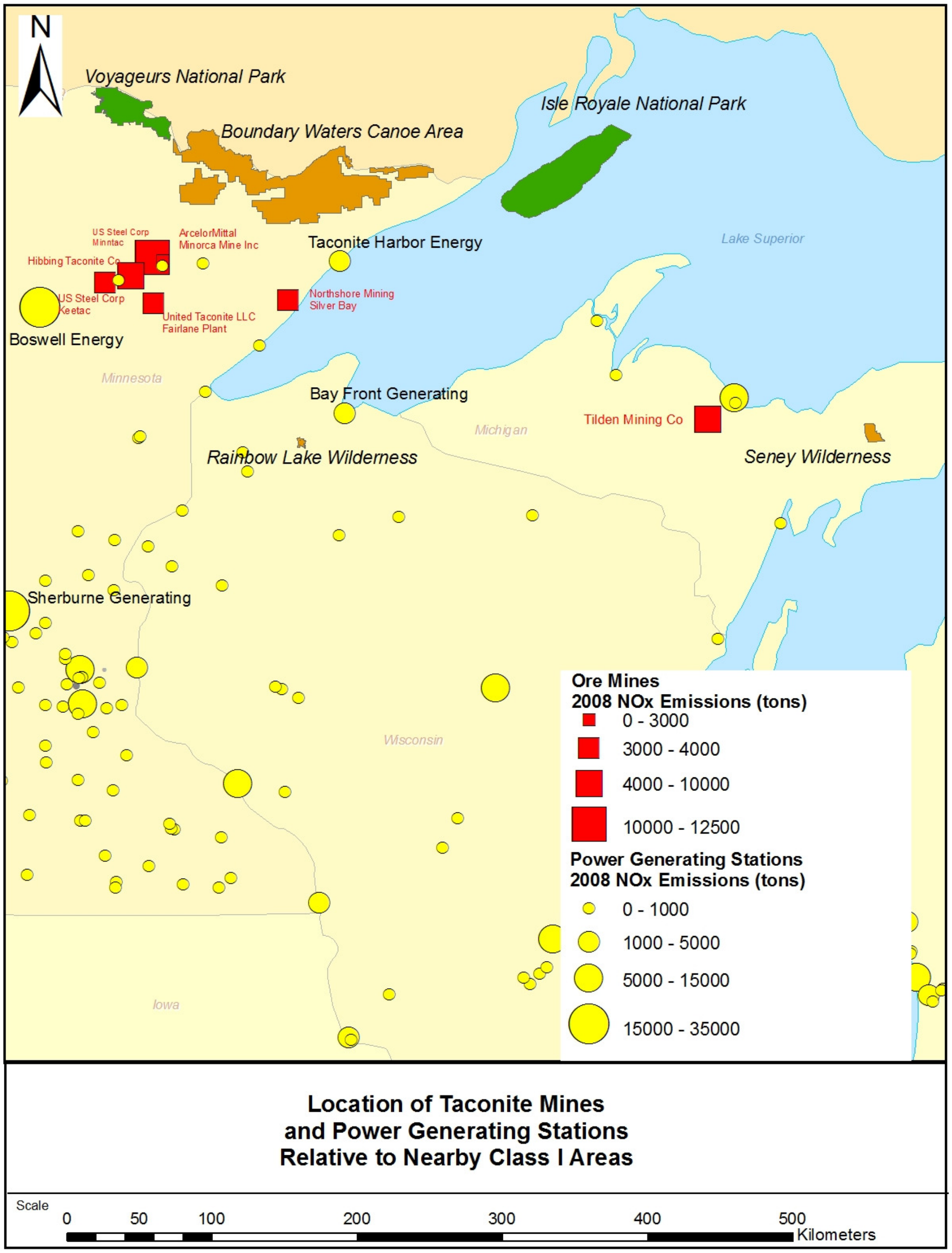
[2] Federal Register. EPA Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule. Federal Register, Vol. 70. (July 6, 2005)

[3] 77FR49308, August 15, 2012.

[4] CALPUFF Dispersion Model, 2000. http://www.epa.gov/scram001 (under 7th Modeling Conference link to Earth Tech web site).

[5] As documented in Appendix D of the IWAQM Phase 2 document, available at www.epa.gov/scram001/7thconf/calpuff/**phase2**.pdf.

Figure 1 Location of Emission Sources Relative To PSD Class I Areas in Minnesota and Michigan



Overprediction Tendency of Visibility Assessment Modeling for BART Emission Reductions

A particularly challenging part of the BART process is the lack of well-defined criteria for determining whether a proposed emission reduction is sufficient, because the criteria for determining BART are somewhat subjective in several aspects, such as what controls are cost-effective and the degree to which the related modeled reductions in haze are sufficient. In addition, the calculations of the visibility improvements, which are intrinsic to establishing the required BART controls, are subject to considerable uncertainty due both to the inherent uncertainty in model predictions and model input parameters. Alternative approaches for applying for technical options and chemistry algorithms in the United States Environmental Protection Agency's (EPA's) preferred CALPUFF model can result in a large range in the modeled visibility improvement. The degree of uncertainty is especially large when NO_X emission controls are considered as a BART option because modeling secondary formation of ammonium nitrate is quite challenging. Accurately modeling the effects of NO_X controls on visibility is very important because they are often very expensive to install and operate. As a collateral effect that needs to be taken into account for BART decisions, such controls can also complicate energy efficiency objectives and strategies to control greenhouse gases and other pollutants. In this paper we discuss why EPA's preferred application of CALPUFF would likely overestimate the predicted visibility impact of emissions, especially NO_X, and the associated effectiveness of NO_X emission controls. Overestimates of the benefits of emissions reduction are evident from the following observations, which are discussed in this document:

- Natural background extinction used in CALPOST to calculate a source's haze impacts is underestimated, which has the effect of exaggerating the impact, which is computed relative to these defined conditions. Natural conditions also dictate how well each state is adhering to the 2018 milestone for achieving progress toward this goal by the year 2064. If the specification of natural conditions is underestimated to the extent that it is not attainable regardless of contributions from U.S. anthropogenic sources, then some states will be penalized for not achieving sufficient progress toward an impossible goal. Appendix A discusses this point in more detail.

- The chemistry in the current EPA-approved version of CALPUFF overestimates winter nitrate haze, especially in conjunction with the specification of high ammonia background concentrations. This conservatism is exacerbated by CALPUFF features that result in overpredictions of all pollutant concentrations. Therefore, CALPUFF modeling will credit BART emission reductions with more visibility improvements than will really occur.

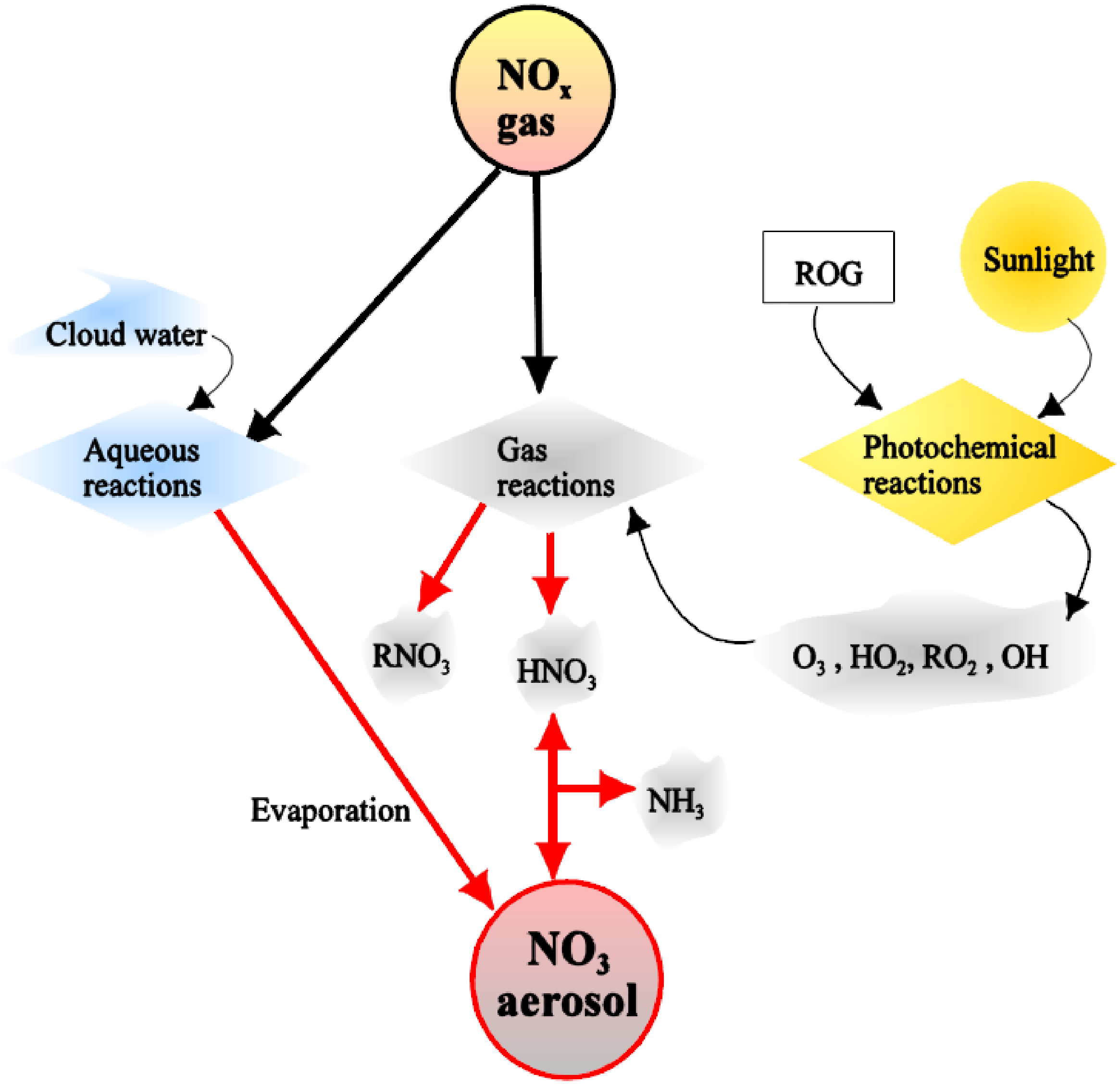
- There are examples where actual significant emission reductions have occurred, where CALPUFF modeling as conducted for BART would predict significant visibility improvements, but no perceptive changes in haze occurred.

Visibility Impact of NO_X Emissions – Unique Aspects and Seasonality

The oxidation of NO_X to total nitrate (TNO_3) depends on the NO_X concentration, ambient ozone concentration, and atmospheric stability. Some of the TNO_3 is then combined with available ammonia in the atmosphere to form ammonium nitrate aerosol in an equilibrium state with HNO_3 gas that is a function

of temperature, relative humidity, and ambient ammonia concentration, as shown in Figure 2[6]. It is important to realize that both CALPUFF and regional photochemical models tend to overpredict nitrate formation, especially in winter. A more detailed discussion of this issue is provided in Appendix B.

Figure 2 CALPUFF II NO_x Oxidation



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[6] Figure 2-32 from CALPUFF Users Guide, available at http://www.src.com/calpuff/download/CALPUFF_UsersGuide.pdf.

In CALPUFF, total nitrate ($TNO_3 = HNO_3 + NO_3$) is partitioned into each species according to the equilibrium relationship between gaseous HNO_3 and NO_3 aerosol. This equilibrium is a function of ambient temperature and relative humidity. Moreover, the formation of nitrate strongly depends on availability of NH_3 to form ammonium nitrate. A summary of the conditions affecting nitrate formation is provided below:

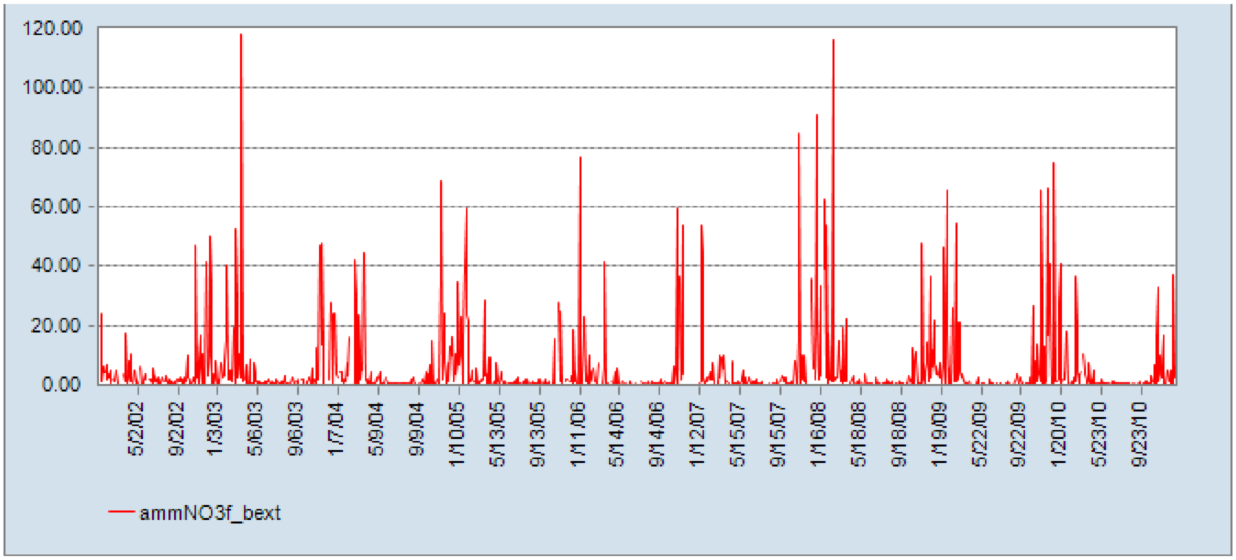
- Colder temperature and higher relative humidity create favorable conditions to form nitrate particulate matter, and therefore more ammonium nitrate is formed;
- Warm temperatures and lower relative humidity create less favorable conditions to form nitrate particulate matter, and therefore less ammonium nitrate is formed;
- Sulfate preferentially scavenges ammonia over nitrates.

For this BART analysis, the effects of temperature and background ammonia concentrations on the nitrate formation are the key to understanding the effects of various NO_X control options. For parts of the country where sulfate concentrations are relatively high and ammonia emissions are quite low, the atmosphere is likely to be in an ammonia-limited regime relative to nitrate formation. Therefore, NO_X emission controls are not very effective in improving regional haze, especially if there is very little ambient ammonia available.

In many cases, the BART visibility assessments ignore the haze increases that occur due to the additional power generation required to operate the control equipment. For NO_X controls, for example, the warm season emissions have minimal visibility impact, but the associated SO_2 emissions from the power generation required to run the controls will increase sulfate haze. These effects have not been considered in the visibility assessment modeling.

It is evident from haze composition plots available from Interagency Monitoring of Protected Visual Environments (IMPROVE) monitors that nitrate haze is confined to winter months. This is clearly shown in Figure 3, which is a timeline of nitrate haze extinction from Boundary Waters Canoe Area Wilderness. Similar patterns are evident for the other Class I areas plotted in Figure 1. The impact of NO_X emissions during the non-winter months (e.g., April through October) is very low.

Figure 3 Boundary Water Canoe Area Wilderness Ammonium Nitrate Extinction, 2002-2010



The occurrence of significant nitrate haze only in the winter months has implications for the effectiveness of haze reductions relative to park attendance. The BART Rule addresses the seasonal issue as follows: "Other ways that visibility improvement may be assessed to inform the control decisions would be to examine distributions of the daily impacts, determine if the time of year is important (e.g., high impacts are occurring during tourist season) . . ."

In this case, the high nitrate impacts are not occurring during the tourist season, especially for the water-dominant Class I areas in Minnesota (Voyageurs and Boundary Waters) that freeze in winter. In fact, for Voyageurs National Park, the typical monthly attendance[7] for an off-season month (November) is only 0.2% that of a peak-season month (July). This is obviously due in part to the brutal winter weather in northern Minnesota (and Michigan) and the lack of boating access to frozen water bodies.

Operations at the Michigan Class I areas in winter are even more restricted. Isle Royale National Park is one of the few national parks to totally close[8] during the winter (generally, during the period of November 1 through April 15). The closure is due to the extreme winter weather conditions and difficulty of access from the mainland across a frozen Lake Superior, for the protection of wildlife, and for the safety and protection of potential visitors. Due to this total closure, there is very little nitrate haze impact in this park during the seasons of the year that it is open, and haze issues for Isle Royale National Park will not be further considered in this report.

The Seney Wilderness Area Visitor Center is open[9] only during the period of May 15th to mid-October. Various trails are generally only open during the same period. The tour loops are closed in the fall, winter, and spring to allow migrating and nesting birds a place to rest or nest undisturbed, and because of large amounts of snow. Although portions of the park are open in the winter, the visitation is greatly reduced due to no visitor center access, no trail or tour loop access, and the severe weather.

Effect of 2009 Recession on Haze in Affected PSD Class I Areas

The effect on haze of a significant (50%) emission reduction from the taconite plants that actually occurred in early 2009 and lasted throughout calendar year 2009 is discussed in this section. This emission reduction was not due to environmental regulations, but rather economic conditions, and affected all pollutants being emitted by the collective group of Minnesota taconite plants, as well as regional power production that is needed to operate the taconite plants.

The annual taconite production[10] from the Minnesota taconite plants in recent years is plotted in Figure 4, along with annual average nitrate concentrations at the nearest Class I area, Boundary Waters Canoe Area (BWCA). The figure shows that the nitrate measured in the park did not respond to the reduction in emissions from the taconite plants. Figures 5 and 6 show the time series[11] of nitrate and sulfate haze in

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[7] As documented at http://www.gorp.com/parks-guide/voyageurs-national-park-outdoor-pp2-guide-cid9423.html.

[8] As noted at http://www.nps.gov/isro/planyourvisit/hours.htm.

[9] As noted at http://www.fws.gov/midwest/seney/visitor_info.html.

[10] Production data is available from taxes levied on taconite production, and the data was supplied by BARR Engineering through a personal communication with Robert Paine of AECOM.

[11] Available from the VIEWS web site at http://views.cira.colostate.edu/web/.

the BWCA over the past several years. Figures for other affected Class I areas (Voyageurs, Seney, and Isle Royale) are shown in Appendix C.

Figure 4 Minnesota Taconite Production and BWCA Nitrate Concentrations

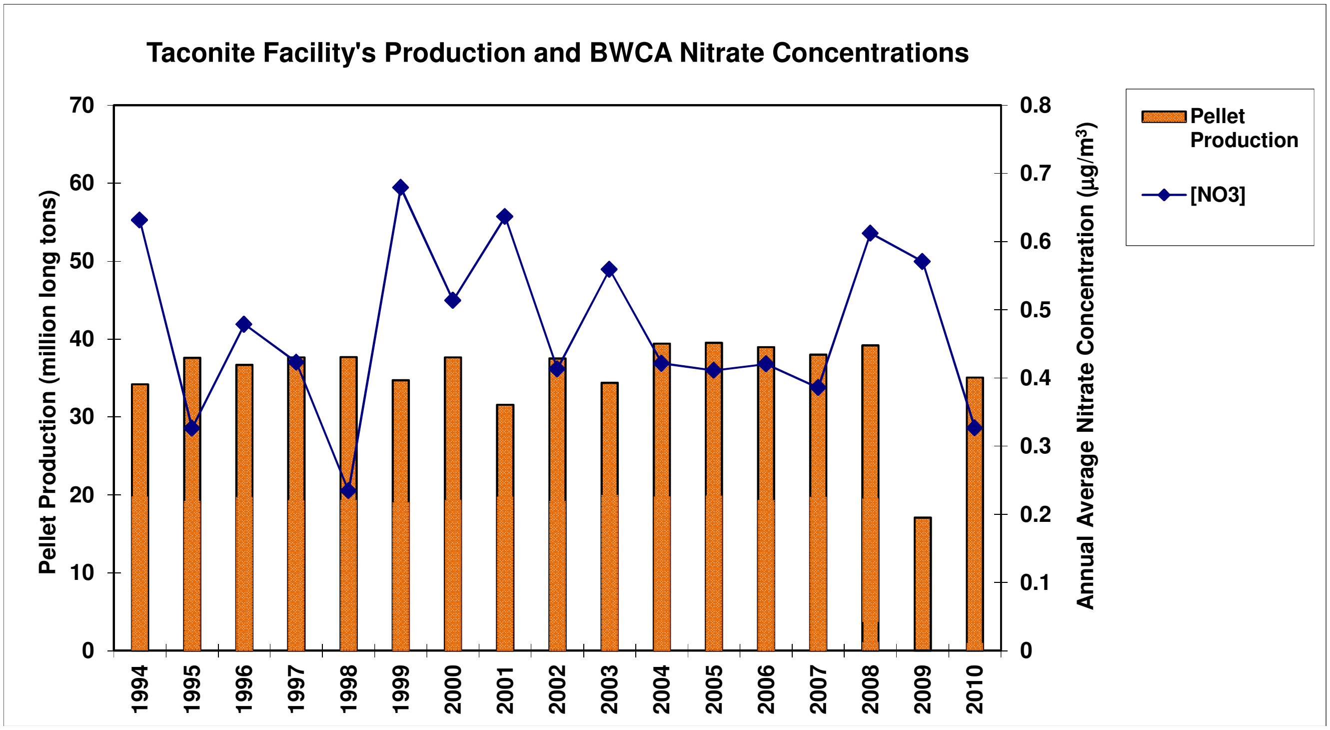


Figure 5 Time Series of Nitrate Haze at Boundary Waters Canoe Area (2002-2010)

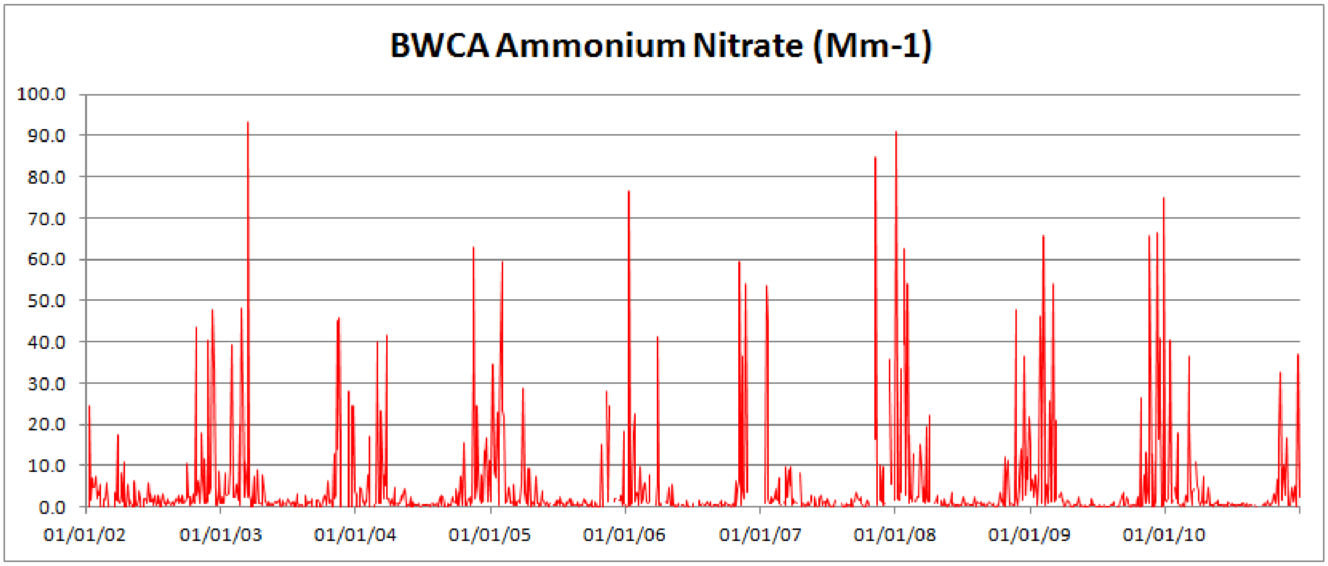
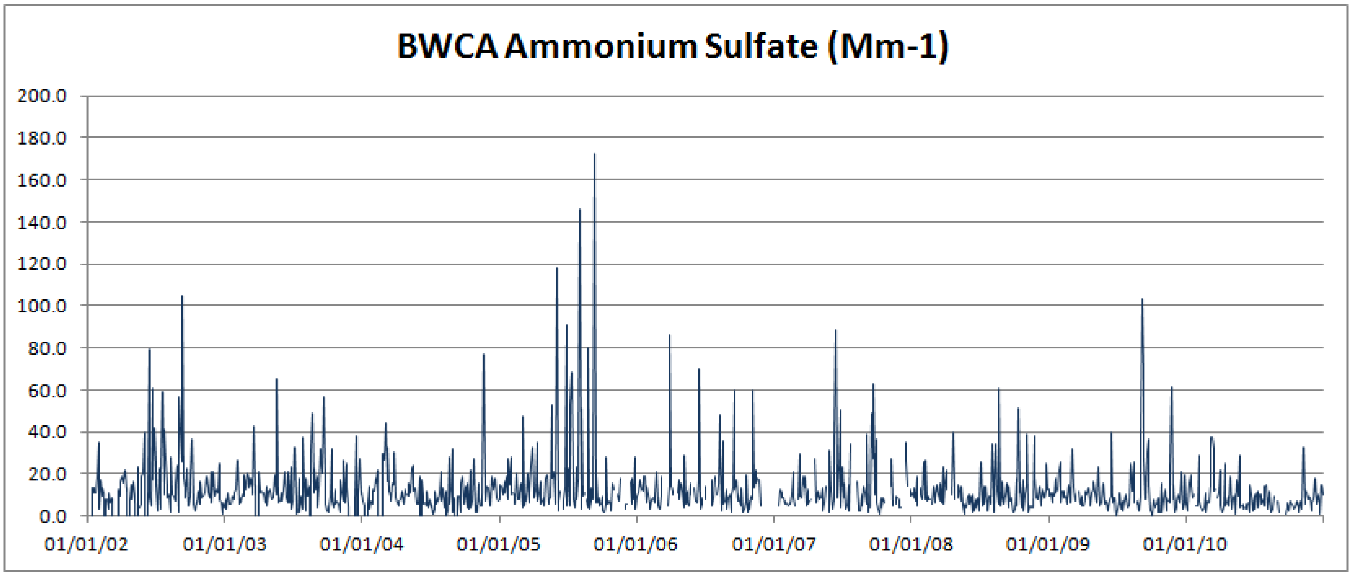


Figure 6 Time Series of Sulfate Haze at Boundary Waters Canoe Area (2002-2010)



It is evident from this information that the haze levels in BWCA did not, in general, decrease during 2009, and were therefore unaffected by emission reductions associated with the taconite production slowdown. It is noteworthy that peak events during mid-2009 in sulfate haze at BWCA when very little taconite production was occurring clearly indicate that minimal haze reduction would likely be associated with taconite plant emission reductions.

It is instructive to review the haze composition time series plots for BWCA for 2008, 2009, and 2010, as shown in Figures 7, 8, and 9.

Figure 7 Haze Composition Figure for Boundary Waters Canoe Area Wilderness, 2008

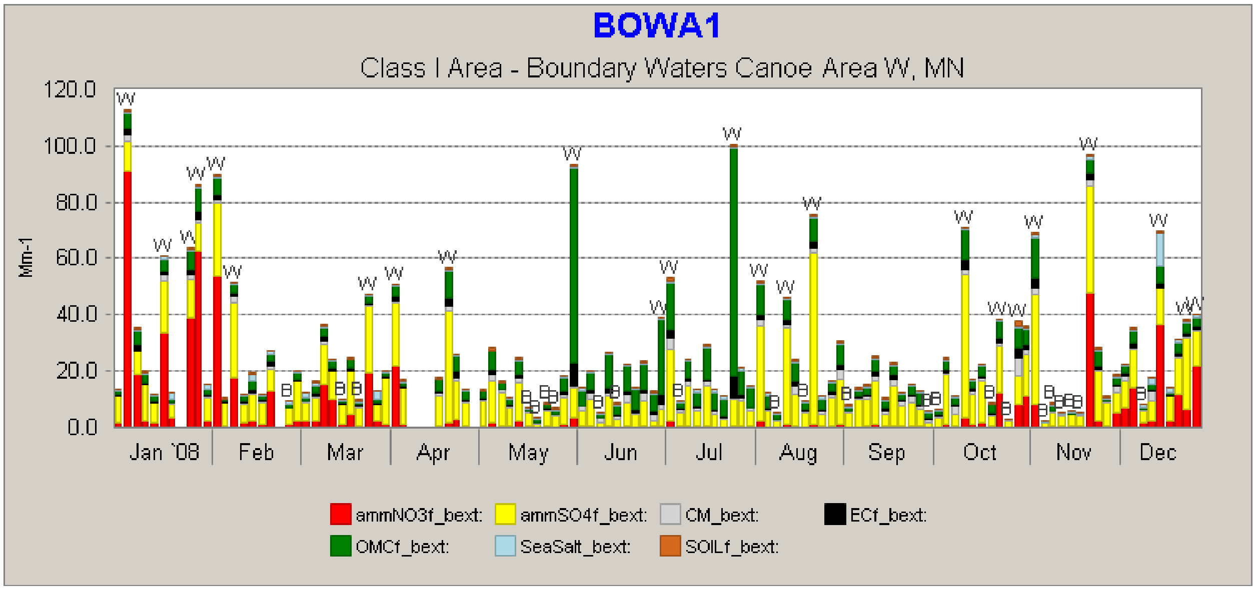


Figure 8 Haze Composition Figure for Boundary Waters Canoe Area Wilderness, 2009

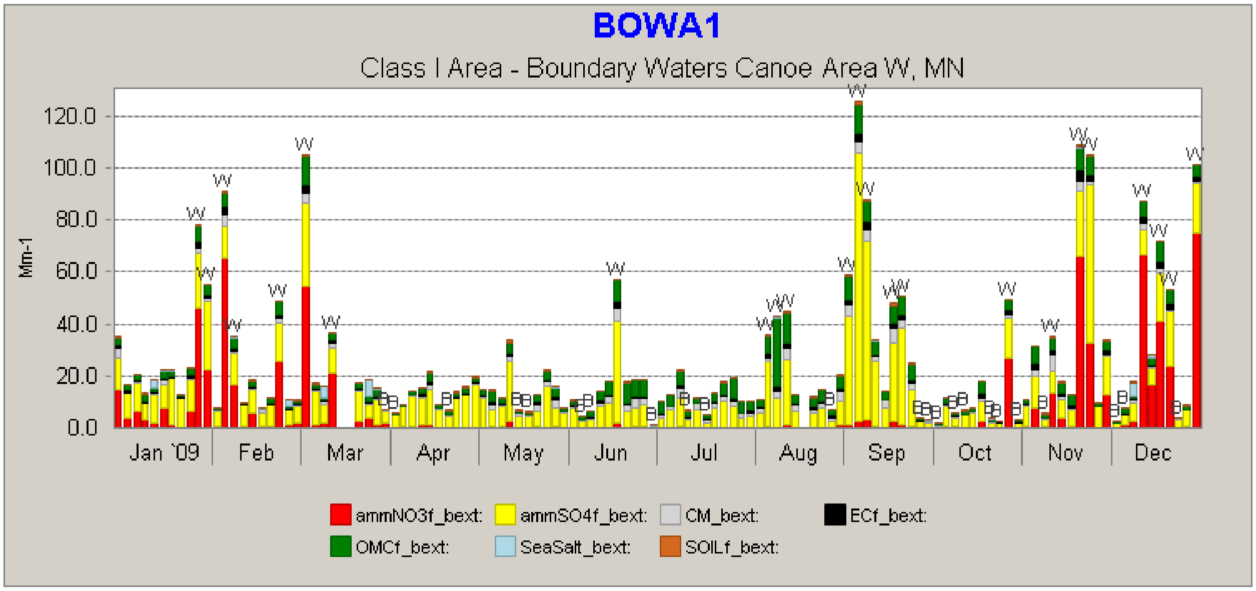
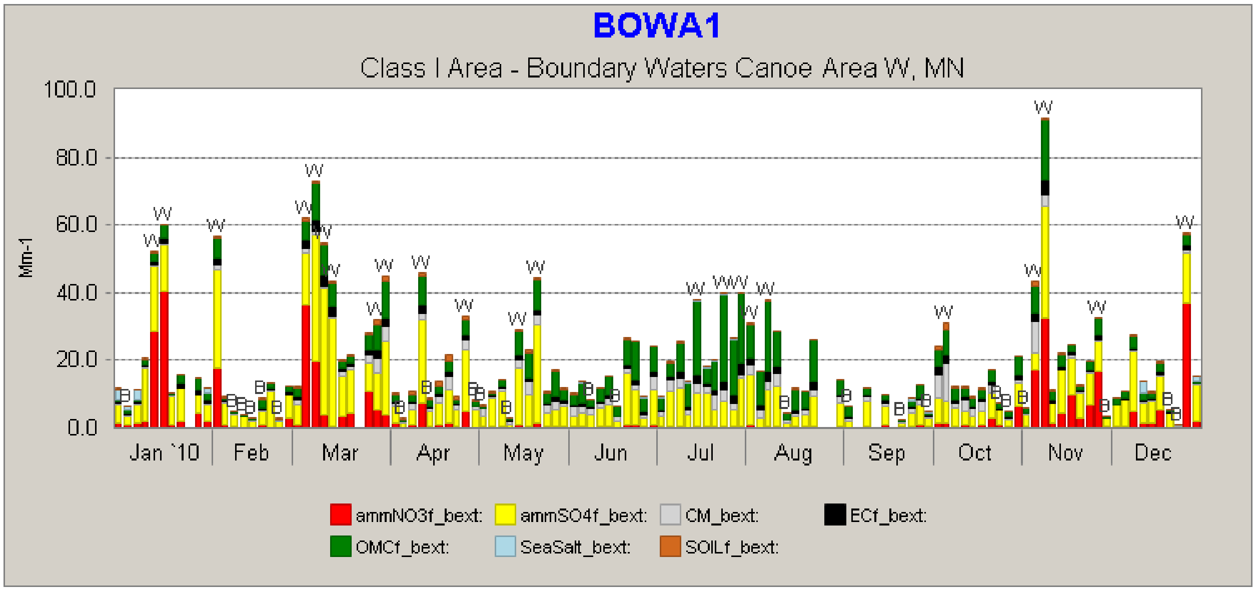


Figure 9 Haze Composition Figure for Boundary Waters Canoe Area Wilderness, 2010



As has been mentioned above, it is evident that the nitrate haze (red bars) is only important during the colder months (November through March). It is also evident that haze from forest fires (green bars) is predominant in the warm weather months, but varies from year to year according to the frequency of wildfires. For example, 2008 was a year of high occurrences of wildfires, while 2009 saw a low frequency, and 2010 was more normal.

The curtailment of taconite plant activity lasted from early 2009 through December 2009, peaking in the summer of 2009. Even so, we see the highest sulfate haze days (yellow bars) in September 2009 when taconite production was half of normal activity. Also, we note high nitrate haze days late in 2009 with the taconite plant curtailment that are comparable in magnitude to full taconite production periods in 2008. We also note that after the taconite plants went back to full production in 2010, the haze levels dropped, apparently due to emissions from other sources and/or states.

These findings suggest that reduction of emissions from the taconite plants will likely have minimal effects on haze in the nearby Class I areas. The fact that the various plants are distributed over a large area means that individual plumes are isolated and generally do not combine with others.

At least one other emission reduction opportunity to determine the effect on visibility improvement has occurred; this is related to the shutdown of the Mohave Generating Station in 2005, and its effect upon visibility in the Grand Canyon National Park. The discussion in Appendix D indicates that although CALPUFF modeling predicted substantial visibility benefits, very little change has occurred since 2005.

Other reasons that visibility assessment models such as CALPUFF could overpredict impacts are listed below.

1) The CALPUFF base case modeled scenario is always a worst-case emission rate which is assumed to occur every day. The actual emissions are often lower, and so the modeled improvement is an overestimate.

2) The way that the predicted concentrations are accounted for in the CALPOST output overstate the impact for even the case where the CALPUFF predictions are completely accurate. The way that CALPOST works is that the peak 24-hour prediction anywhere in a Class I area is the only information saved for each predicted day. The predicted impact for each day is effectively assumed to be a) always in the same place; and b) in all portions of the Class I area. Therefore, the 98th percentile day's prediction could be comprised of impacts in 8 different places that are all erroneously assumed to be co-located.

3) CALPUFF does not simulate dispersion and transport accurately over a full diurnal cycle, during which significant wind direction shear can occur (and is not properly accounted for by CALPUFF). This can result in plumes that are more cohesive than actually occur.

4) As discussed above, it is well established that nitrate predictions are often overstated by CALPUFF v. 5.8, especially in winter.

5) Natural conditions as input to CALPOST are not attainable, and their use will exaggerate the simulated visibility impacts of modeled emissions.

Interstate Non-Interference with Regional Haze Rule SIPs from Taconite Plant Emissions

An issue that is a recurring one for a number of state implementation plans (SIPs) is whether emissions from one state can interfere with haze reduction plans for downwind states. For Minnesota, it would be expected that emission reductions undertaken to reduce haze in Minnesota Class I areas (Voyageurs and Boundary Waters) would also act to reduce haze in other Class I areas. In the case of Minnesota's

taconite plant emissions, earlier discussions of the potentially affected Class I areas indicated that only the Class I areas in northern Michigan (Isle Royale National Park and Seney Wilderness Area) are close enough and in a general predominant wind direction to merit consideration. The closer of these two parks, Isle Royale, is closed to the public from November 1 through April 15, and haze effects there would not be affected by NO_X emissions because those effects are only important in the winter. Since Minnesota's Class I areas are located generally upwind of Michigan sources, the impact of Michigan sources on these Class I areas is expected to be small. This is confirmed in the Particulate Matter Source Apportionment Technology (PSAT) plots shown below.

Regional photochemical modeling studies[12] conducted by the CENRAP Regional Planning Organization, of which Minnesota is a part, shows contributions of various states as well as international contributions for haze impacts in the Michigan Class I areas. Relevant figures from the Iowa RHR SIP report for 2018 emission inventory haze impacts are reproduced below for Isle Royale National Park (Figure 10) and Seney Wilderness Area (Figure 11).

The modeling conducted for this analysis, using CAMx, shows that the relative contribution to haze for all Minnesota sources to sulfate haze in Isle Royale National Park is low, consisting of only 10% of the sulfate haze. The effect of 2018 emissions from Minnesota sources at the more distant Seney Wilderness Area is even lower, with the state's emissions ranking 9th among other jurisdictions analyzed for this Class I area. Therefore, it is apparent that Minnesota sources, and certainly the subset including taconite plants, would not be expected to interfere with other state's progress toward the 2018 milestone associated with the Regional Haze Rule.

Figures 12 and 13, reproduced from the Iowa RHR SIP report for Boundary Waters and Voyageurs, respectively, indicate that Michigan sources rank 11th and 12th, respectively, for haze impacts in these two areas for projected 2018 emissions. Therefore, as expected, Michigan sources are not expected to interfere with Minnesota's RHR SIP for progress in 2018.

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[12] See, for example, the Iowa State Implementation Plan for Regional Haze report at http://www.iowadnr.gov/portals/idnr/uploads/air/insidednr/rulesandplanning/rh_sip_final.pdf, Figures 11.3 and 11.4.

Figure 10 PSAT Results from CENRAP CAMx Modeling for Isle Royale National Park

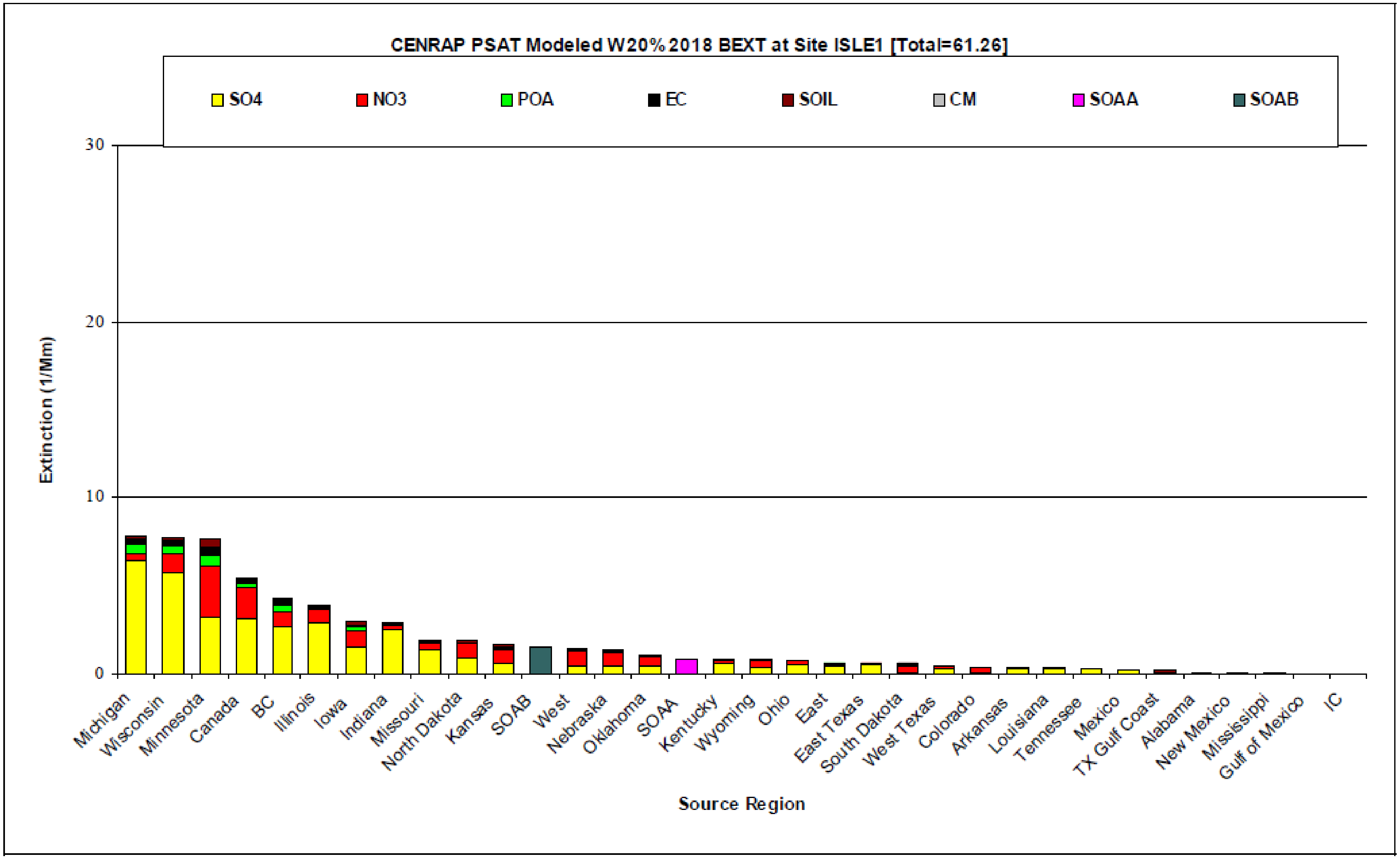


Figure 11.3. Source apportion contributions by region and pollutant to ISLE in 2018.

Figure 11 PSAT Results from CENRAP CAMx Modeling for Seney Wilderness Area

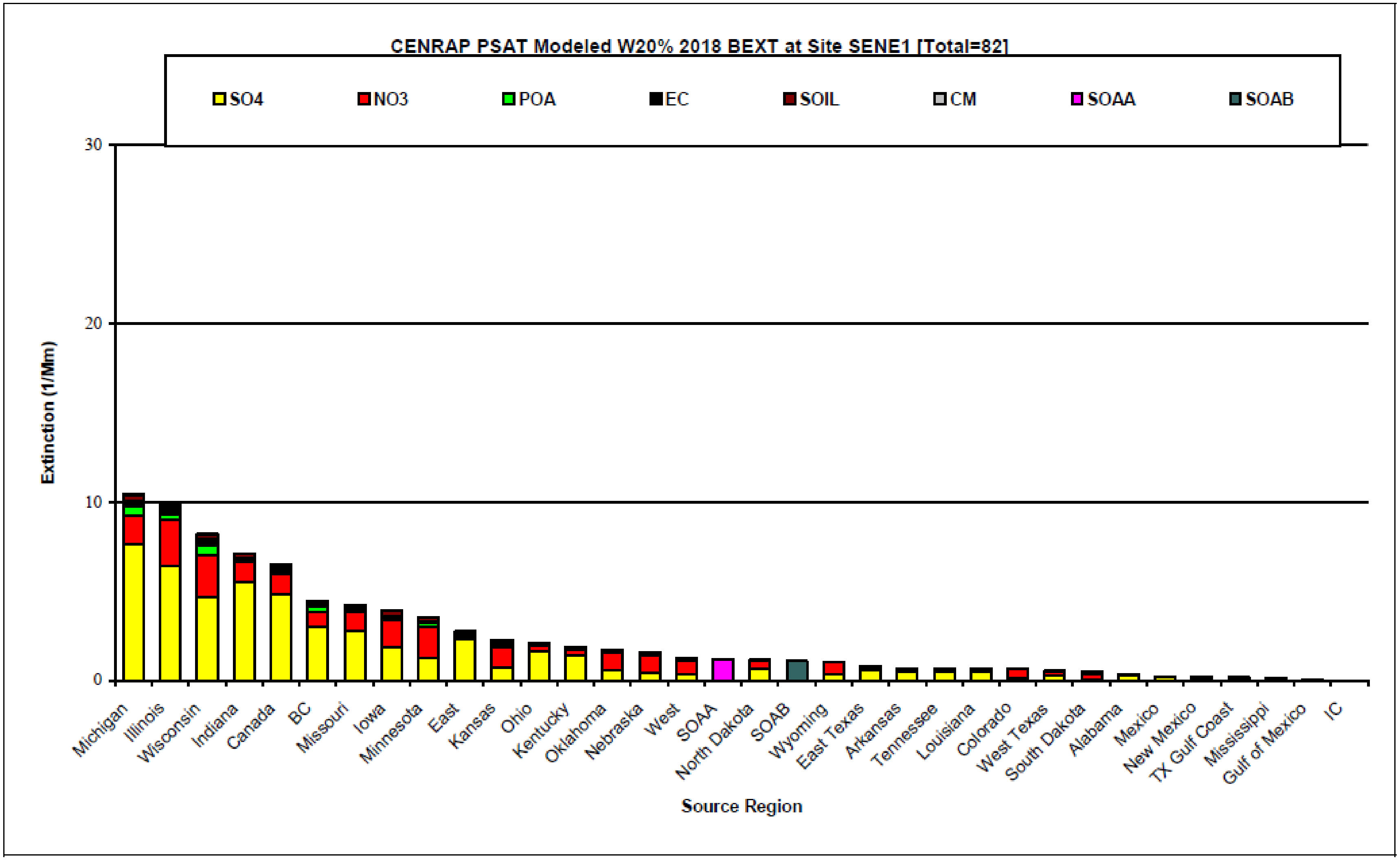


Figure 11.4. Source apportion contributions by region and pollutant to SENE in 2018.

Figure 12 PSAT Results from CENRAP CAMx Modeling for Boundary Waters Canoe Area Wilderness

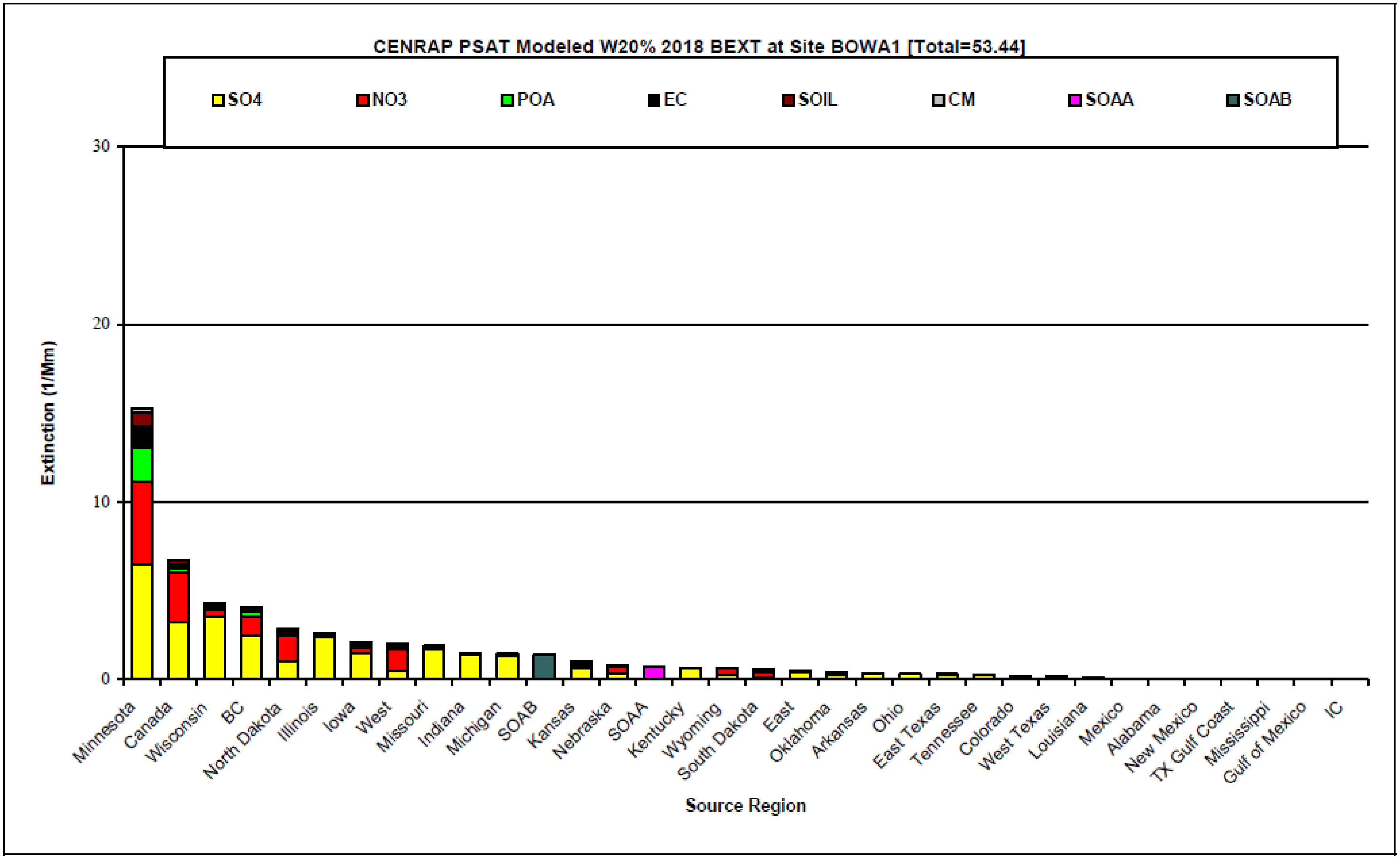


Figure 11.1. Source apportion contributions by region and pollutant to BOWA in 2018.

Figure 13 PSAT Results from CENRAP CAMx Modeling for Voyageurs National Park

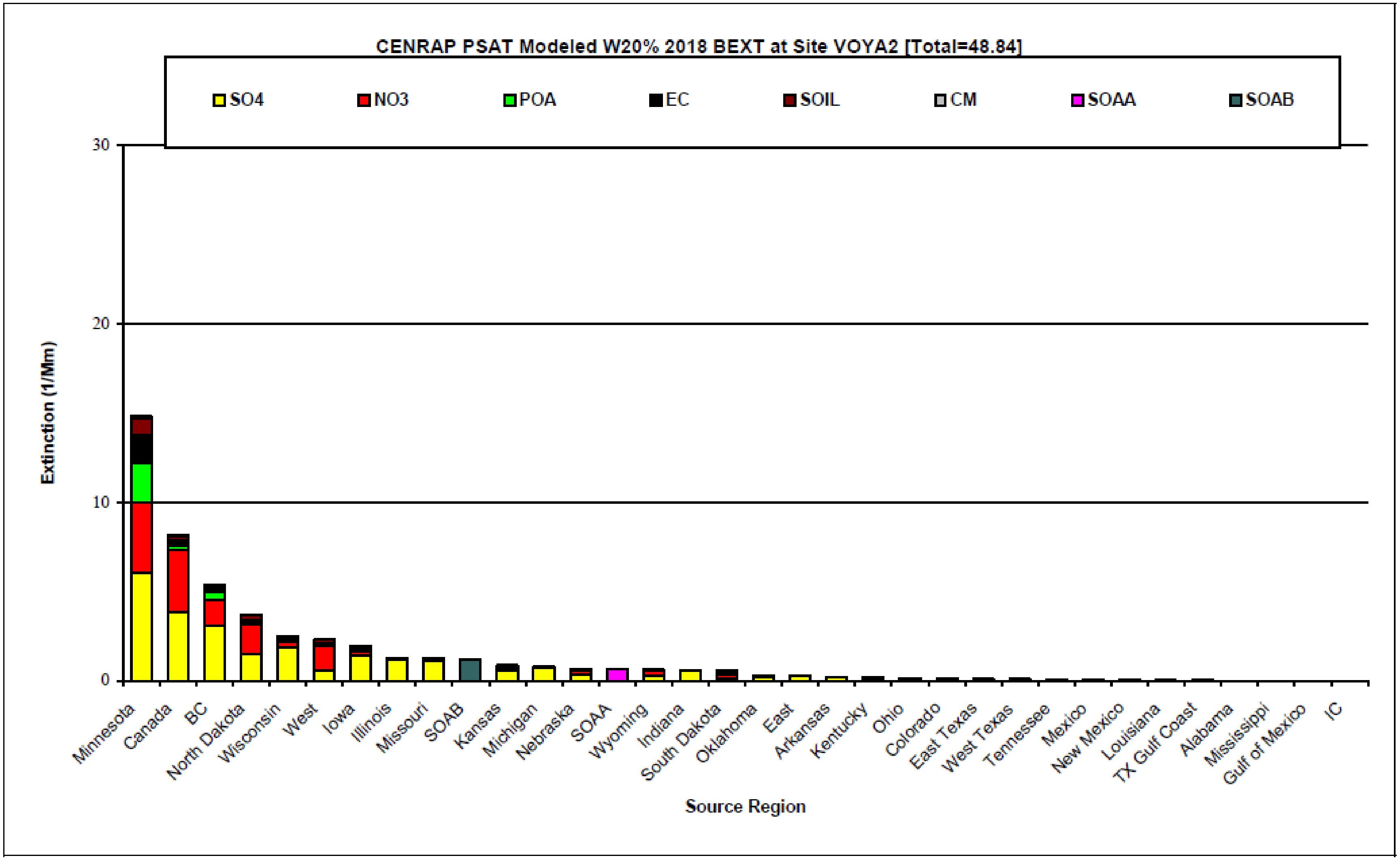


Figure 11.2. Source apportion contributions by region and pollutant to VOYA in 2018.

CONCLUSIONS

EPA's preferred modeling tools to assess the visibility improvement from BART controls will likely overestimate the predicted visibility improvement. While this is expected for all pollutants, it is especially true for NO_X emission controls. This occurs for several reasons:

- Natural background conditions, which are used in the calculation of haze impacts due to anthropogenic emissions, are mischaracterized as too clear, which exaggerates the impact of emission sources. Overly clean natural conditions can lead to the erroneous conclusion that some states are not adhering to the 2018 milestone because they need to achieve progress toward an impossible goal by the year 2064.
- The chemistry in the current EPA-approved version of CALPUFF as well as regional photochemical models overestimates winter nitrate haze, especially with the use of high ammonia background concentrations. There are other CALPUFF features that result in overpredictions of all pollutant concentrations. Therefore, BART emission reductions will be credited with visibility modeling for more visibility improvements than will really occur. We recommend that EPA adopt CALPUFF v. 6.42, which includes substantial improvements in the chemistry formulation. We also recommend the use of seasonally varying ammonia background concentrations, in line with observations and the current capabilities of CALPUFF.
- In addition to CALPUFF, the use of regional photochemical models results in significant nitrate haze overpredictions for Minnesota Class I area predictions.
- The modeled base case scenario is always a worst-case emission rate, assumed to occur every day. The actual emissions are often lower, and so the modeled improvement is an overestimate.

Impacts of the taconite plants' NO_X emissions are confined to winter months by the unique chemistry for nitrate particle formation. During these months, the attendance at the parks is greatly reduced by the closure of significant portions of the parks and the inability to conduct boating activities on frozen water bodies. In the case of Isle Royale National Park, there is total closure in the winter, lasting for 5 ½ months. The BART rule makes a provision for the consideration of such seasonal impacts. The imposition of NO_X controls year-round would not only have minimal benefits in the peak visitation season of summer, but also could lead to visibility disbenefits due to the increased power requirements (and associated emissions) needed for their operation, an effect that has not been considered in the visibility modeling.

Evidence of models' tendency for overprediction are provided in examples of actual significant emission reductions that have resulted in virtually no perceptive changes in haze, while visibility assessment modeling as conducted for BART would predict significant visibility improvements. These examples include the shutdown of the Mohave Generating Station (and minimal visibility effects at the Grand Canyon) as well as the economic slowdown that affected emissions from the taconite plants in 2009.

An analysis of the impact of the visibility impacts of Minnesota BART sources on Michigan's Class I areas, and vice versa indicates that the effects on the other state's Class I areas is minor. The taconite plant emissions are not expected to interfere with the ability of other states to achieve their required progress under the Regional Haze Rule.

APPENDIX A

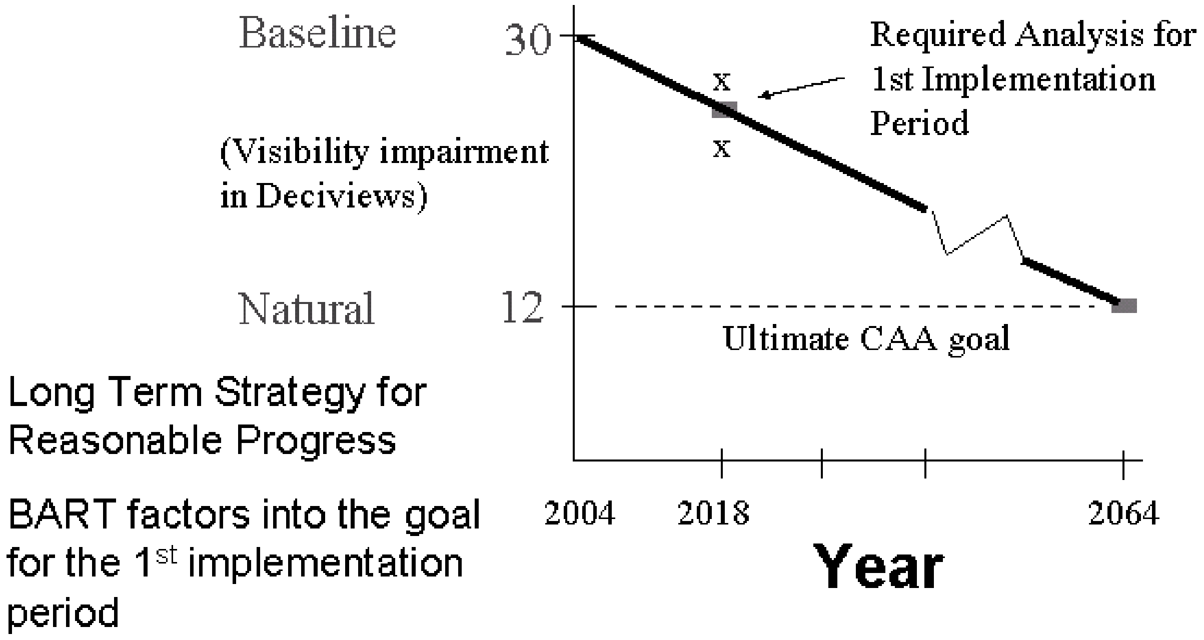
THE REGIONAL HAZE RULE GOAL OF NATURAL CONDITIONS

An important consideration in the ability for a state to meet the 2018 Uniform Rate of Progress (URP) goal is the definition of the end point goal of “natural conditions” for the worst 20% haze days; see Figure A-1, which illustrates this concept). Note that while achieving improved visibility for the worst 20% haze days, the RHR also stipulates that there should not be deterioration of visibility for the best 20%, or clearest, days. One way to define that goal would be the elimination of all man-made emissions. This raises some other questions, such as:

- To what categories of emissions does the RHR pertain?
- Does the current definition of natural conditions include non-anthropogenic or uncontrollable emissions?

The default natural background assumed by EPA in their 2003 guidance document[13] is not realistic. The discussion in this section explains why EPA’s default natural conditions significantly understate the true level of natural haze, including the fact that there are contributors of haze that are not controllable (and that are natural) that should be included in the definition of natural visibility conditions. In addition, one important aspect of the uncontrollable haze, wildfires, is further discussed regarding the biased quantification of its contribution to natural haze due to suppression of wildfires during the 20th century.

Figure A-1: Illustration of the Uniform Rate of Progress Goal



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[13] *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule*, (U.S. Environmental Protection Agency, September 2003). http://www.epa.gov/ttncaaa1/t1/memoranda/rh_envcurhr_gd.pdf.

In its RHR SIP, North Dakota[14] noted in Section 9.7 that,

"Achieving natural conditions will require the elimination of all anthropogenic sources of emissions. Given current technology, achieving natural conditions is an impossibility. Any estimate of the number of years necessary to achieve natural visibility conditions would require assumptions about future energy sources, technology improvements for sources of emissions, and every facet of human behavior that causes visibility impairing emissions. The elimination of all SO_2 and NO_x emissions in North Dakota will not achieve the uniform rate of progress for this [2018], or any future planning period. Any estimate of the number of years to achieve natural conditions is questionable because of the influence of out-of-state sources."

It will be extremely difficult, if not impossible, to eliminate all anthropogenic emissions, even if natural conditions are accurately defined. It will be even more daunting to try to reach the goal if natural conditions are significantly understated, and as a result, states are asked to control sources that are simply not controllable. It is clear that the use of EPA default natural conditions leads to unworkable and absurd results for one state's (North Dakota's) ability to determine the rate of progress toward an unattainable goal. The definition of natural conditions that can be reasonably attained for a reasonable application of USEPA's Regional Haze Rule should be revised for all states.

The objective of the following discussion is to summarize recent modeling studies of natural visibility conditions and to suggest how such studies can be used in evaluating the uniform rate of progress in reducing haze to attain natural visibility levels. In addition, the distinction between natural visibility and policy relevant background visibility is discussed. Treatment of this issue by other states, such as Texas, is also discussed.

Regional Haze Issues for Border States

There are similarities between the Regional Haze Rule (RHR) challenges for border states such as North Dakota and Texas in that both states have significant international and natural contributions to regional haze in Class I areas in their states. The Texas Commission on Environmental Quality (TCEQ) has introduced alternative RHR glide paths to illustrate the State's rate of progress toward the RHR goals. Since TCEQ has gone through the process of a RHR State Implementation Plan (SIP) development and comment period, it is instructive to look at the TCEQ approach, the comments provided by the Federal Land Managers to TCEQ, and TCEQ's reaction to the comments.

Similarities to be considered for the RHR SIP development in border states, such as North Dakota and Texas, include the items listed below.

- These states have Class I areas for which a considerable fraction of the regional haze is due to international transport or transport from other regions of the United States.

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[14] North Dakota Dep. of Health, 2010. North Dakota State Implementation Plan for Regional Haze. http://www.ndhealth.gov/AQ/RegionalHaze/Regional%20Haze%20Link%20Documents/Main%20SIP%20Sections%201-12.pdf.
.

- As a result, there is a substantial reduction in SO_2 and NO_x emissions from the BART-eligible sources in each state, but this reduction results in a relatively small impact on regional haze mitigation. Additional emission reductions would, therefore, have a minimal benefit on visibility improvement at substantial cost.
- In the Regional Haze SIP development, these states have attempted to account for the effects of anthropogenic emissions that they can control in alternative analyses. These analysis result in a finding that the in-state emission reductions come closer to meeting the Uniform Rate of Progress glide path goals for 2018. However, due to the low probability of impact of these sources on the worst 20% days, the effectiveness of in-state emission controls on anthropogenic sources subject to controls is inherently limited.

TCEQ decided that coarse and fine PM measured at the Class I areas were due to natural causes (especially on the worst 20% days), and adjusted the natural conditions endpoint accordingly. The Federal Land Managers (FLMs) agreed with this approach for the most part[15], but suggested that 80% of these concentrations would be due to natural causes, and 20% would be due to anthropogenic causes. TCEQ determined from a sensitivity analysis that the difference in these two approaches was too small to warrant a re-run of their analysis, but it is important that the FLMs agreed to a state-specific modification of the natural conditions endpoint, and this substantially changed the perceived rate of progress of the SIP plan toward the altered natural conditions endpoint.

Although the TCEQ did not address other particulate matter components in this same way, a review of air parcel back trajectories previously available from the IMPROVE web site (http://views.cira.colostate.edu/web/) suggests that other components, such as organic matter due to wildfires, could be substantially due to natural causes, so that this component should also be considered as at least partially natural.

The TCEQ discussed the issue of how emissions from Mexico could interfere with progress on the RHR, but they did not appear to adjust the glide path based upon Mexican emissions. On the other hand, in its weight of evidence analysis, North Dakota did evaluate adjustments based upon anthropogenic emissions that could not be controlled from Canadian sources, but did not take into account any specific particulate species that are generally not emitted by major anthropogenic sources of SO_2 and NO_X.

Natural Haze Levels

The Regional Haze Rule establishes the goal that natural visibility conditions should be attained in Federal Class I areas by the year 2064. Additionally, the states are required to determine the uniform rate of progress (URP) of visibility improvement necessary to attain the natural visibility goal by 2064. Finally, each state must develop a SIP identifying reasonable control measures that will be adopted well before 2018 to reduce source emissions of visibility-impairing particulate matter (PM) and its precursors (SO_2 and NO_x).

Estimates of natural haze levels have been developed by the EPA for visibility planning purposes and are described in the above-referenced EPA 2003 document. The natural haze estimates were based on ambient data analysis of selected PM species for days with good visibility and are shown in Table A-1.

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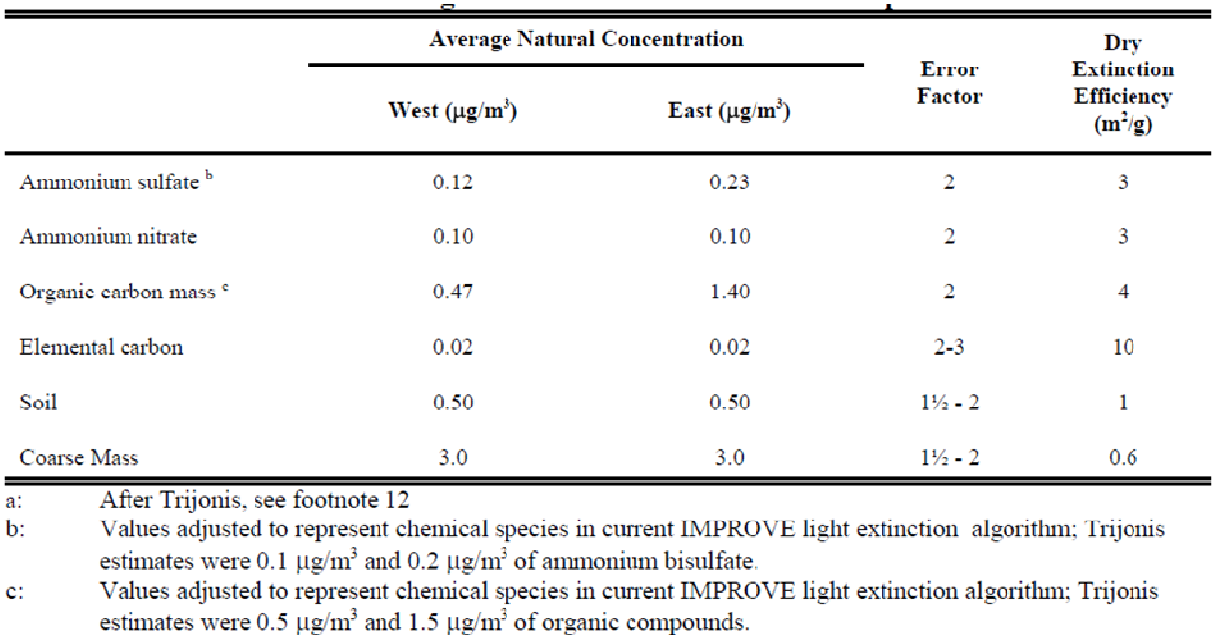
[15] See Appendix 2-2 at http://www.tceq.state.tx.us/implementation/air/sip/bart/haze_appendices.html.

These estimates were derived from Trijonis[16] and use two different sets of natural concentrations for the eastern and western U.S. Tombach[17] provides a detailed review and discussion of uncertainty in the USEPA natural PM estimates. Natural visibility can be calculated using the IMPROVE equation which calculates the light scattering caused by each component of PM. After much study, changes in the IMPROVE equation and in the method for calculating natural visibility were developed in 2005 and are described by Pitchford et al.[18]

Table A-1: Average Natural Levels of Aerosol Components from Table 2-1 of *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule* (EPA, 2003)



	Average Natural Concentration		Error Factor	Dry Extinction Efficiency (m^2/g)
	West ($\mu g/m^3$)	East ($\mu g/m^3$)		
Ammonium sulfate [b]	0.12	0.23	2	3
Ammonium nitrate	0.10	0.10	2	3
Organic carbon mass [c]	0.47	1.40	2	4
Elemental carbon	0.02	0.02	2-3	10
Soil	0.50	0.50	1½ - 2	1
Coarse Mass	3.0	3.0	1½ - 2	0.6

a: After Trijonis, see footnote 12

b: Values adjusted to represent chemical species in current IMPROVE light extinction algorithm; Trijonis estimates were 0.1 $\mu g/m^3$ and 0.2 $\mu g/m^3$ of ammonium bisulfate.

c: Values adjusted to represent chemical species in current IMPROVE light extinction algorithm; Trijonis estimates were 0.5 $\mu g/m^3$ and 1.5 $\mu g/m^3$ of organic compounds.

The EPA guidance also makes provision for refined estimates of site-specific natural haze that differ from the default values using either data analysis or model simulations. However, most states have continued to use the default natural haze levels for calculating the progress toward natural visibility conditions.

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[16] Trijonis, J. C. Characterization of Natural Background Aerosol Concentrations. Appendix A in Acidic Deposition: State of Science and Technology. Report 24. Visibility: Existing and Historical Conditions -- Causes and Effects. J. C. Trijonis, lead author. National Acid Precipitation Assessment Program: Washington, DC, 1990.

[17] Tombach, I., (2008) *Natural Haze Levels Sensitivity -- Assessment of Refinements to Estimates of Natural Conditions,* Report to the Western Governors Association, January 2008, available at http://www.wrapair.org/forums/aamrf/projects/NCB/index.html.

[18] Pitchford, M., Malm, W., Schichtel, B., Kumar, N., Lowenthal, D., Hand, J., Revised Algorithm for Estimating Light Extinction from IMPROVE Particle Speciation Data, J. Air & Waste Manage, Assoc. 57: 1326 – 1336, 2007.

Tombach and Brewer[19] reviewed natural sources of PM and identified several Class I areas for which evidence supports adjustments to the natural levels. Tombach[8] also reviewed estimates of natural haze levels and proposed that, instead of using two sets of default natural PM concentrations for the eastern and western US, a large number of sensitivity zones should be developed that reflect regional variability in natural PM sources. Tombach[8] also suggested that modeling studies are a possible approach to further revise estimates of natural PM concentrations.

Previous modeling studies have shown that the estimates of natural visibility described above for "clean" days will differ from the results of model simulations when United States anthropogenic emissions are totally eliminated (Tonnesen et al., 2006[20]; Koo et al., 2010[21]), especially when natural wild fire emissions are included in the model simulation. Because the URP is calculated using model simulations of PM on the 20% of days with the worst visibility, wild fires and other extreme events can result in estimated levels of natural haze (even without any contribution of US anthropogenic sources) that can be significantly greater than the natural levels used in the EPA guidance for URP calculation. This could make it difficult or impossible for states to identify emissions control measures sufficient to demonstrate the URP toward attaining visibility goals because the endpoint is unachievable even if all US anthropogenic emissions are eliminated, as North Dakota has already determined even for the interim goal in 2018.

Previous Suppression of Wildfire Activity and its Effect upon the EPA Default Natural Conditions

Throughout history, except for the past few decades, fires have been used to clear land, change plant and tree species, sterilize land, maintain certain types of habitat, among other purposes. Native Americans used fires as a technique to maintain certain pieces of land or to improve habitats. Although early settlers often used fires in the same way as the Native Americans, major wildfires on public domain land were largely ignored and were often viewed as an opportunity to open forestland for grazing.

Especially large fires raged in North America during the 1800s and early 1900s. The public was becoming slowly aware of fire's potential for life-threatening danger. Federal involvement in trying to control forest fires began in the late 1890s with the hiring of General Land Office rangers during the fire season. When the management of the forest reserves (now called national forests) was transferred to the newly formed Forest Service in 1905, the agency took on the responsibility of creating professional standards for firefighting, including having more rangers and hiring local people to help put out fires.

Since the beginning of the 20th century, fire suppression has resulted in a buildup of vegetative "fuels" and catastrophic wildfires. Recent estimates of background visual range, such as Trijonis[16], have underestimated the role of managed fire on regional haze. Since about 1990, various government agencies have increased prescribed burning to reduce the threat of dangerous wildfires, and the

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[19] Tombach, I., and Brewer, P. (2005). Natural Background Visibility and Regional Haze Goals in the Southeastern United States. *J. Air & Waste Manage. Assoc. 55*, 1600-1620.

[20] Tonnesen, G., Omary, M., Wang, Z., Jung, C.J., Morris, R., Mansell, G., Jia, Y., Wang, B., and Z. Adelman (2006) Report for the Western Regional Air Partnership Regional Modeling Center, University of California Riverside, Riverside, California, November. (http://pah.cert.ucr.edu/aqm/308/reports/final/2006/WRAP-RMC_2006_report_FINAL.pdf).

[21] Koo B., C.J. Chien, G. Tonnesen, R. Morris , J. Johnson, T. Sakulyanontvittaya, P. Piyachaturawat, and G.Yarwood, 2010. Natural emissions for regional modeling of background ozone and particulate matter and impacts on emissions control strategies. Atm. Env., 44, 2372-2382.

increased haze due to these fires is often more of an impairment to visibility than industrial sources, especially for NO_X reductions that are only effective in winter, the time of the lowest tourist visitation in most cases.

The National Park Service indicates at http://www.nps.gov/thro/parkmgmt/firemanagement.htm for the Theodore Roosevelt National Park that:

"For most of the 20th Century, wildfires were extinguished immediately with the assumption that doing so would protect lives, property, and natural areas. However, following the unusually intense fire season of 1988, agencies including the National Park Service began to rethink their policies." Even this policy is not always successful, as experienced by the USDA Forest Service[22] in their management of wildfires near the Boundary Waters Canoe Area that can contribute significantly to visibility degradation during the peak tourist season. In this case, even small fires, if left unchecked, have been known to evolve into uncontrollable fires and then require substantial resources to extinguish.

EPA's 2003 "Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program" acknowledges that wildfires are a contributor to natural visibility conditions, but the data used in estimates of natural conditions were taken during a period of artificial fire suppression so that the true impact of natural wildfires is understated. The report notes that "data should be available for EPA and States to develop improved estimates of the contribution of fire emissions to natural visibility conditions in mandatory Federal Class I areas over time." As noted by several studies noted above, the impact due to natural fire levels is underestimated in the EPA natural visibility background estimates. The consequences of the artificially low estimates of natural visibility conditions include the distortion of Reasonable Progress analyses and also to BART modeling results that overestimate the visibility improvement achievable from NO_X emission reductions due to the use of inaccurate natural visibility conditions.

Recommendations for an Improved Estimate of Visibility Natural Conditions

A reasonable approach would be to combine the effects of the uncontrollable particulate matter components and the emissions from international sources to determine a new glide path endpoint that is achievable by controlling (only) U.S. anthropogenic emissions. To compute this new endpoint, regional photochemical modeling using CMAQ or CAMx could be conducted for the base case (already done) and then for a future endpoint case that has no U.S. anthropogenic emissions, but with natural particulate matter emissions (e.g., dust, fires, organic matter) as well as fine particulate, SO_2 and NO_x emissions associated with all non-U.S. sources set to the current baseline levels. The simulation should include an higher level of wildfire activity than in the recent past to reflect a truer level of fire activity before manmade suppression in the 20th century. Then, states could use a relative reduction factor (RRF) approach to determine the ratio of the haze impacts between the base case and the reasonable future case, and then apply the RRF values to the baseline haze to obtain a much more reasonable "natural conditions" haze endpoint. The more accurate natural background would also result in a reduction in the degree to which CALPUFF modeling overstates visibility improvement from emission reductions.

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[22] See explanation at http://www.msnbc.msn.com/id/48569985/ns/us_news-environment/t/forest-service-gets-more-aggressive-small-fires/.

APPENDIX B

MODEL OVERPREDICTION ISSUES FOR WINTERTIME NITRATE HAZE

This appendix includes a discussion of CALPUFF predictions for nitrate haze, followed by more general issues with CALPUFF predictions.

CALPUFF Predictions of Nitrate Haze

Secondary pollutants such as nitrates and sulfates contribute to light extinction in Class I areas. The CALPUFF model was approved by EPA for use in BART determinations to evaluate the effect of these pollutants on visibility in Class I areas. CALPUFF version 5.8 (the current guideline version) uses the EPA-approved MESOPUFF II chemical reaction mechanism to convert SO_2 and NO_X emissions to secondary sulfate and nitrate. This section describes how secondary pollutants, specifically nitrate, are formed and the factors affecting their formation, especially as formulated in CALPUFF.

In the CALPUFF model, the oxidation of NO_X to nitric acid (HNO_3) depends on the NO_X concentration, ambient ozone concentration, and atmospheric stability. Some of the nitric acid is then combined with available ammonia in the atmosphere to form ammonium nitrate aerosol in an equilibrium state that is a function of temperature, relative humidity, and ambient ammonia concentration. In CALPUFF, total nitrate ($TNO_3 = HNO_3 + NO_3$) is partitioned into gaseous HNO_3 and NO_3 particles according to the equilibrium relationship between the two species. This equilibrium is a function of ambient temperature and relative humidity. Moreover, the formation of nitrate particles *strongly* depends on availability of NH_3 to form ammonium nitrate, as shown in Figure 6[23]. The figure on the left shows that with 1 ppb of available ammonia and fixed temperature and humidity (for example, 275 K and 80% humidity), only 50% of the total nitrate is in the form of particulate matter. When the available ammonia is increased to 2 ppb, as shown in the figure on the right, as much as 80% of the total nitrate is in the particulate form. Figure B-1 also shows that colder temperatures and higher relative humidity favor particulate nitrate formation. A summary of the conditions affecting nitrate formation are listed below:

- Colder temperature and higher relative humidity create more favorable conditions to form nitrate particulate matter in the form of ammonium nitrate;
- Warmer temperatures and lower relative humidity create less favorable conditions for nitrate particulate matter resulting in a small fraction of total nitrate in the form of ammonium nitrate;
- Ammonium sulfate formation preferentially scavenges available atmospheric ammonia over ammonium nitrate formation. In air parcels where sulfate concentrations are high and ambient ammonia concentrations are low, there is less ammonia available to react with nitrate, and less ammonium nitrate is formed.

The effects of temperature and background ammonia concentrations on the nitrate formation are the key to understanding the effects of various NO_X control options. For the reasons discussed above, the seasons with lower temperatures are the most likely to be most important for ammonium nitrate formation when regional haze is more effectively reduced by controlling NO_X.

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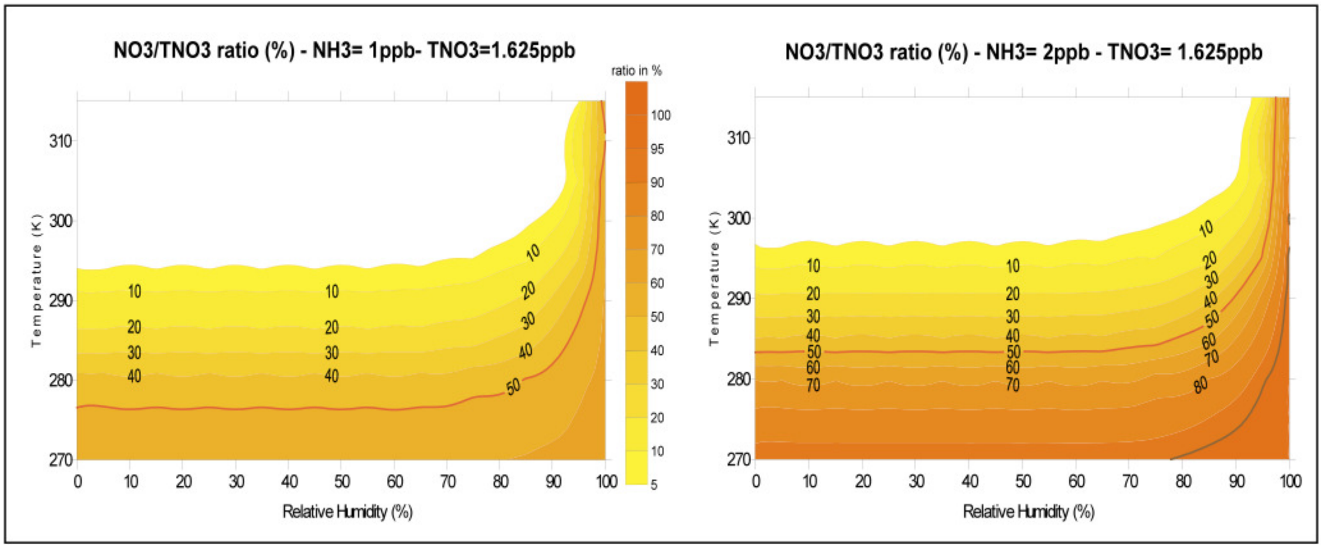
[23] Scire, Joseph. CALPUFF MODELING SYSTEM. CALPUFF course presented at Chulalongkorn University, Bangkok, Thailand. May 16-20, 2005; slide 40 available at http://aqnis.pcd.go.th/tapce/plan/4CALPUFF%20slides.pdf, accessed March 2011.

Figure B-1: NO_3/HNO_3 Equilibrium Dependency on Temperature and Humidity



Sensitivity of CALPUFF Haze Calculations to Background Ammonia Concentration

In an independent analysis, the Colorado Department of Public Health and Environment (CDPHE) performed a sensitivity modeling analysis to explore the effect of the specified ammonia concentration applied in CALPUFF on the predicted visibility impacts for a source with high NO_X emissions relative to SO_2 emissions[24]. The results of the sensitivity modeling are shown in Figure B-2. It is noteworthy that the largest sensitivity occurs for specified ammonia input between 1 and 0.1 ppb. In that factor-of-ten range, the difference in the peak visibility impact predicted by CALPUFF is slightly more than a factor of three. This sensitivity analysis shows that the specification of background ammonia is very important in terms of the magnitude of visibility impacts predicted by CALPUFF. The fact that regional, diurnal and seasonal variations of ambient ammonia concentrations are not well-characterized and mechanisms not well-understood effectively limits the effectiveness of CALPUFF in modeling regional haze, especially in terms of the contribution of ammonium nitrate.

It is also noteworthy that CALPUFF version 5.8's demonstrated over-predictions of wintertime nitrate can be mitigated to some extent by using lower winter ammonia background values, although there is not extensive measurement data to determine the ambient ammonia concentrations. This outcome showing the superiority of the monthly-varying background ammonia concentrations was found by Salt River

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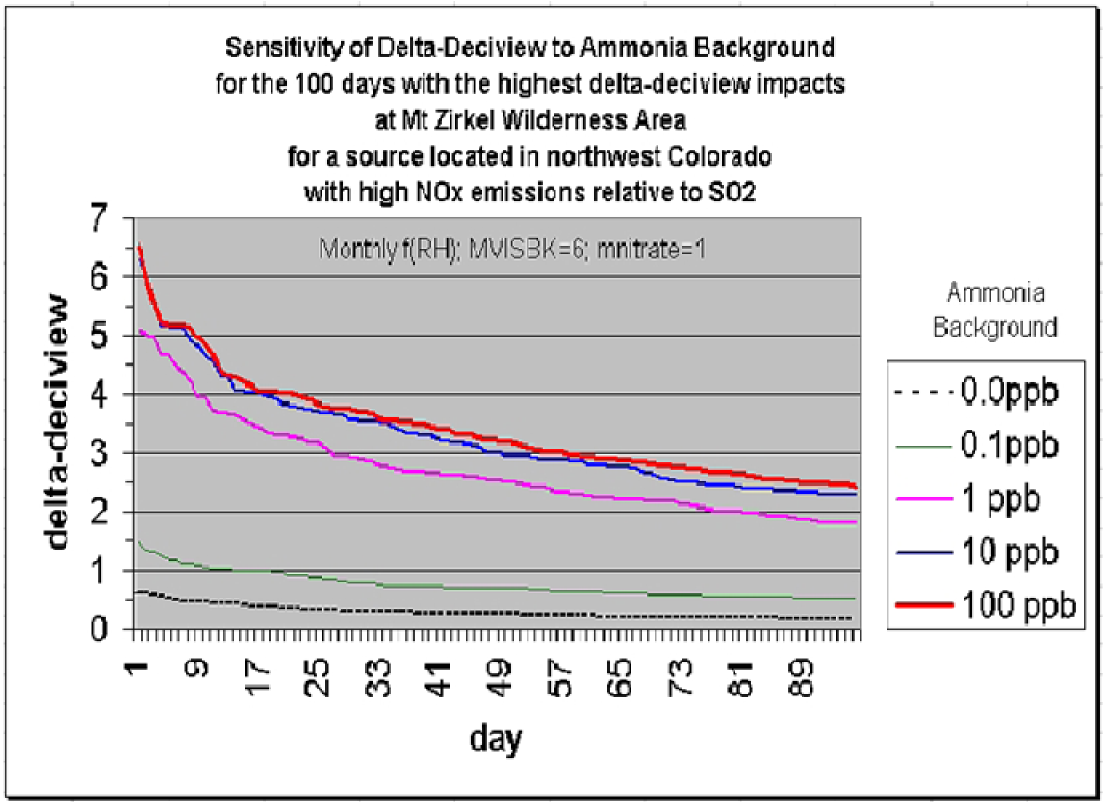
[24] Supplemental BART Analysis: CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis (DRAFT), revised June 25, 2010, available at http://www.colorado.gov/airquality/documents/Draft-ColoradoSupplementalBARTAnalysisCALPUFFProtocol-25June2010.pdf. (2010)

Project in case studies of the Navajo Generating Station impacts on Grand Canyon monitors, as presented[25] to EPA in 2010.

It is important to note that 14 years ago in 1998, when the IWAQM Phase 2 guidance[26] was issued, CALPUFF did not even have the capability of accommodating monthly ammonia background concentrations; only a single value was allowed. Since then, CALPUFF has evolved to be able to receive as input monthly varying ammonia concentrations. EPA's guidance on the recommended input values that are constant all year has not kept pace with the CALPUFF's capability. The weight of evidence clearly indicates that the use of monthly varying ammonia concentrations with lower wintertime values will result in more accurate predictions.

Figure B-2: CDPHE Plot of Sensitivity of Visibility Impacts Modeled by CALPUFF for Different Ammonia Backgrounds.



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[25] Salt River Project, 2010. Measurements of Ambient Background Ammonia on the Colorado Plateau and Visibility Modeling Implications. Salt River Project, P.O. Box 52025 PAB352, Phoenix, Arizona 85072.

[26] IWAQM Phase 2 Summary Report and Recommendations (EPA-454/R-98-019), EPA OAQPS, December 1998). http://www.epa.gov/scram001/7thconf/calpuff/phase2.pdf.

Independent Studies of the Effect of Model Chemistry on Nitrate Predictions

The Regional Haze BART Rule acknowledged that CALPUFF tends to overestimate the amount of nitrate that is produced. In particular, the overestimate of ammonium nitrate concentrations on visibility at Class I areas is the greatest in the winter, when temperatures (and visitation) are lowest, the nitrate concentrations are the greatest, and the sulfate concentrations tend to be the least due to reduced oxidation rates of SO_2 to sulfate.

On page 39121, the BART rule[27] stated that: "…the simplified chemistry in the [CALPUFF] model tends to magnify the actual visibility effects of that source."

On page 39123, the BART rule stated that: "We understand the concerns of commenters that the chemistry modules of the CALPUFF model are less advanced than some of the more recent atmospheric chemistry simulations. In its next review of the Guideline on Air Quality Models, EPA will evaluate these and other newer approaches[28]."

EPA did not conduct such an evaluation, but the discussion below reports on the efforts of other investigators.

A review of independent evaluations of the CALPUFF model is reported here, with a focus on identifying studies that address the nitrate chemistry used in the model. Morris et al.[29] reported that the CALPUFF MESOPUFF II transformation rates were developed using temperatures of 86, 68 and 50°F. Therefore, the 50°F minimum temperature used in development of the model could result in overestimating sulfate and nitrate formation in colder conditions. These investigators found that CALPUFF tended to overpredict nitrate concentrations during winter by a factor of about three.

A recent independent study of the CALPUFF performance by Karamchandani et al (referred to here as the KCBB study) is highly relevant to this issue[30]. The KCBB study presented several improvements to the Regional Impacts on Visibility and Acid Deposition (RIVAD) chemistry option in CALPUFF, an alternative treatment that was more amenable to an upgrade than the MESOPUFF II chemistry option. Among other items, the improvements included the replacement of the original CALPUFF secondary particulate matter (PM) modules by newer algorithms that are used in current state-of-the-art regional air quality models such as CMAQ, CMAQ-MADRID, CAMx and REMSAD, and in advanced puff models

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[27] July 6, 2005 Federal Register publication of the Regional Haze BART rule.

[28] The next (9th) EPA modeling conference was held in 2008, during which the concepts underlying the chemistry upgrades in CALPUFF 6.42 were presented. However, EPA failed to conduct the promised evaluation in its review of techniques at that conference held 4 years ago. As a result of the 10th EPA modeling conference held in March 2012, EPA appears to be continuing to rely upon CALPUFF version 5.8, which it admitted in the July 6, 2005 BART rule has serious shortcomings.

[29] Morris, R., Steven Lau and Bonyoung Koo. Evaluation of the CALPUFF Chemistry Algorithms. Presented at A&WMA 98th Annual Conference and Exhibition, June 21-25, 2005 Minneapolis, Minnesota. (2005)

[30] Karamchandani, P., S. Chen, R. Bronson, and D. Blewitt. Development of an Improved Chemistry Version of CALPUFF and Evaluation Using the 1995 SWWYTAF Data Base. Presented at the Air & Waste Management Association Specialty Conference on Guideline on Air Quality Models: Next Generation of Models, October 28-30, 2009, Raleigh, NC. (2009)

such as SCICHEM. In addition, the improvements included the incorporation of an aqueous-phase chemistry module based on the treatment in CMAQ. Excerpts from the study papers describing each of the improvements made to CALPUFF in the KCBB study are repeated below.

Gas-Phase Chemistry Improvements

The KCBB study applied a correction to CALPUFF in that the upgraded model was modified to keep track of the puff ozone concentrations between time steps. The authors also updated the oxidation rates of SO_2 and nitrogen dioxide (NO_2) by the hydroxide ion (OH^-) to the rates employed in contemporary photochemical and regional PM models.

Treatment of Inorganic Particulate Matter

The KCBB study scientists noted that the EPA-approved version of CALPUFF currently uses a simple approach to simulate the partitioning of nitrate and sulfate between the gas and particulate phases. In this approach, sulfate is appropriately assumed to be entirely present in the particulate phase, while nitrate is assumed to be formed by the reaction between nitric acid and ammonia.

The KCBB study implemented an additional treatment for inorganic gas-particle equilibrium, based upon an advanced aerosol thermodynamic model referred to as the ISORROPIA model[31]. This model is currently used in several state-of-the-art regional air quality models. With this new module, the improved CALPUFF model developed in the KCBB study includes a treatment of inorganic PM formation that is consistent with the state of the science in air quality modeling, and is critical for the prediction of regional haze due to secondary nitrate formation from NO_X emissions.

Treatment of Organic Particulate Matter

The KCBB study added a treatment for secondary organic aerosols (SOA) that is coupled with the corrected RIVAD scheme described above. The treatment is based on the Model of Aerosol Dynamics, Reaction, Ionization and Dissolution (MADRID)[32,33], which treats SOA formation from both anthropogenic and biogenic volatile organic compound emissions.

Aqueous-Phase Chemistry

The current aqueous-phase formation of sulfate in both CALPUFF's RIVAD and MESOPUFF II schemes is currently approximated with a simplistic treatment that uses an arbitrary pseudo-first order rate in the presence of clouds (0.2% per hour), which is added to the gas-phase rate. There is no explicit treatment

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[31] Nenes A., Pilinis C., and Pandis S.N. Continued Development and Testing of a New Thermodynamic Aerosol Module for Urban and Regional Air Quality Models, *Atmos. Env.* **1998**, 33, 1553-1560.

[32] Zhang, Y., B. Pun, K. Vijayaraghavan, S.-Y. Wu, C. Seigneur, S. Pandis, M. Jacobson, A. Nenes and J.H. Seinfeld. Development and Application of the Model of Aerosol Dynamics, Reaction, Ionization and Dissolution (MADRID), *J. Geophys. Res.* **2004**, 109, D01202, doi:10.1029/2003JD003501.

[33] Pun, B., C. Seigneur, J. Pankow, R. Griffin, and E. Knipping. An upgraded absorptive secondary organic aerosol partitioning module for three-dimensional air quality applications, 24th Annual American Association for Aerosol Research Conference, Austin, TX, October 17-21, 2005. (2005)

of aqueous-phase SO_2 oxidation chemistry. The KCBB study incorporated into CALPUFF a treatment of sulfate formation in clouds that is based on the treatment that is used in EPA's CMAQ model.

CALPUFF Model Evaluation and Sensitivity Tests

The EPA-approved version of CALPUFF and the version with the improved chemistry options were evaluated using the 1995 Southwest Wyoming Technical Air Forum (SWWYTAF) database[34], available from the Wyoming Department of Environmental Quality. The database includes MM5 output for 1995, CALMET and CALPUFF codes and control files, emissions for the Southwest Wyoming Regional modeling domain, and selected outputs from the CALPUFF simulations. Several sensitivity studies were also conducted to investigate the effect of background NH_3 concentrations on model predictions of PM nitrate. Twice-weekly background NH_3 concentrations were provided from monitoring station observations for the Pinedale, Wyoming area. These data were processed to calculate seasonally averaged background NH_3 concentrations for CALPUFF.

Two versions of CALPUFF with different chemistry modules were evaluated with this database:

1. MESOPUFF II chemistry using the Federal Land Managers' Air Quality Related Values Work Group (FLAG) recommended background NH_3 concentration of 1 ppb for arid land. As discussed previously, the MESOPUFF II algorithm is the basis for the currently approved version of CALPUFF that is being used for BART determinations throughout the United States.

2. Improved CALPUFF RIVAD/ARM3 chemistry using background values of NH_3 concentrations based on measurements in the Pinedale, Wyoming area, as described above.

PM sulfate and nitrate were predicted by the two models and compared with actual measured values obtained at the Bridger Wilderness Area site from the IMPROVE network and the Pinedale site from the Clean Air Status and Trends Network (CASTNET). For the two model configurations evaluated in this study, the results for PM sulfate were very similar, which was expected since the improvements to the CALPUFF chemistry were anticipated to have the most impact on PM nitrate predictions. Therefore, the remaining discussion focuses on the performance of each model with respect to PM nitrate.

The EPA-approved CALPUFF model was found to significantly overpredict PM nitrate concentrations at the two monitoring locations, by a factor of two to three. The performance of the version of CALPUFF with the improved RIVAD chemistry was much better, with an overprediction of about 4% at the Pinedale CASTNET site and of about 28% at the Bridger IMPROVE site.

In an important sensitivity analysis conducted within the KCBB study, both the EPA-approved version of CALPUFF and the improved version were run with a constant ammonia background of 1 ppb, as recommended by IWAQM Phase II[35]. The results were similar to those noted above: the improved

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[34] Wyoming Department of Environmental Quality. 1995 Southwest Wyoming Technical Air Forum (SWWYTAF) database. Background and database description are available at http://deq.state.wy.us/aqd/prop/2003AppF.pdf. (2010)

[35] Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Long-Range Transport Modeling, EPA-454/R-98-019. (1998)

CALPUFF predictions were about two to three times lower than those from the EPA-approved version of CALPUFF. This result is similar to the results using the seasonal observed values of ammonia, and indicates that the sensitivity of the improved CALPUFF model to the ammonia input value is potentially less than that of the current EPA-approved model.

Similar sensitivity was noted by Scire et al. in their original work in the SWWYATF study[36], in which they tested seasonally varying levels of background ammonia in CALPUFF (using 0.23 ppb in winter, for example; see Figure B-3. The sensitivity modeling for predicting levels of nitrate formation shows very similar results to those reported in the KCBB study.

These findings indicate that to compensate for the tendency of the current EPA-approved version of CALPUFF to overpredict nitrates, the background ammonia values that should be used as input in CALPUFF modeling should be representative of isolated areas (e.g., Class I areas).

On November 3, 2010, TRC released a new version (6.42) of CALPUFF to fix certain coding "bugs" in EPA-approved version 5.8 and to improve the chemistry module. Additional enhancements to CALPUFF version 6.42 have been reported at EPA's 10th modeling conference in March 2012 by Scire[37], who also has conducted recent evaluations of this version in comparison to the regulatory version (5.8). Despite the evidence that this CALPUFF version is a generation ahead of the currently approved version for modeling secondary particulate formation, EPA has not acted to adopt it as a guideline model. Even with evidence provided by independent investigators[29,30] that also indicate that wintertime nitrate estimated by CALPUFF version 5.8 is generally overpredicted by a factor between 2 and 4, EPA has not taken steps to adopt the improved CALPUFF model, noting that extensive peer review, evaluations, and rulemaking are still needed for this adoption to occur. In the meantime, EPA, in retaining CALPUFF version 5.8 as the regulatory model for regional haze predictions, is ignoring the gross degree of overestimation of particulate nitrate and is thus ensuring that regional haze modeling conducted for BART is overly conservative. EPA's delay in adopting CALPUFF version 6.42 will thus result in falsely attributing regional haze mitigation to NO_X emission reductions.

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[36] Scire, J.S., Z-X Wu, D.G. Strimaitis and G.E. Moore. The Southwest Wyoming Regional CALPUFF Air Quality Modeling Study – Volume I. Prepared for the Wyoming Dept of Environmental Quality. (2001)

[37] Scire, J., 2012. New Developments and Evaluations of the CALPUFF Model. http://www.epa.gov/ttn/scram/10thmodconf/presentations/3-5-CALPUFF_Improvements_Final.pdf.

OVERPREDICTIONS OF NITRATE HAZE BY REGIONAL PHOTOCHEMICAL MODELS

The overprediction tendency for modeling of wintertime nitrate haze is not limited to CALPUFF. Even the state-of-the-art regional photochemical models are challenged in getting the right ammonium nitrate concentrations. This is evident in a presentation[38] made by Environ to the CENRAP Regional Planning Organization in 2006. The relevant figures from the Ralph Morris presentation (shown in Figures B-4 and B-5 below) indicate that both CMAQ and CAMx significantly overpredict nitrate haze in winter at Voyageurs National Park, by about a factor of 2. This is shown by the height of the red portion of the composition plot stacked bars between the observed and predicted timelines. It is noteworthy that Minnesota and EPA have relied upon this modeling approach for their BART determinations. Similar to CALPUFF, as discussed above, the agency modeling is prone to significantly overpredicting wintertime nitrate haze, leading to an overestimate of visibility improvement with NO_X emission reductions.

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[38] http://pah.cert.ucr.edu/aqm/cenrap/meetings.shtml, under “MPE”, slides 9 and 10.

Figure B-3: Sensitivity Study of Nitrate Predictions at Bridger Wilderness Area for Input Ammonia Concentrations to CALPUFF (0.23, 0.5, and 1.0 ppb).

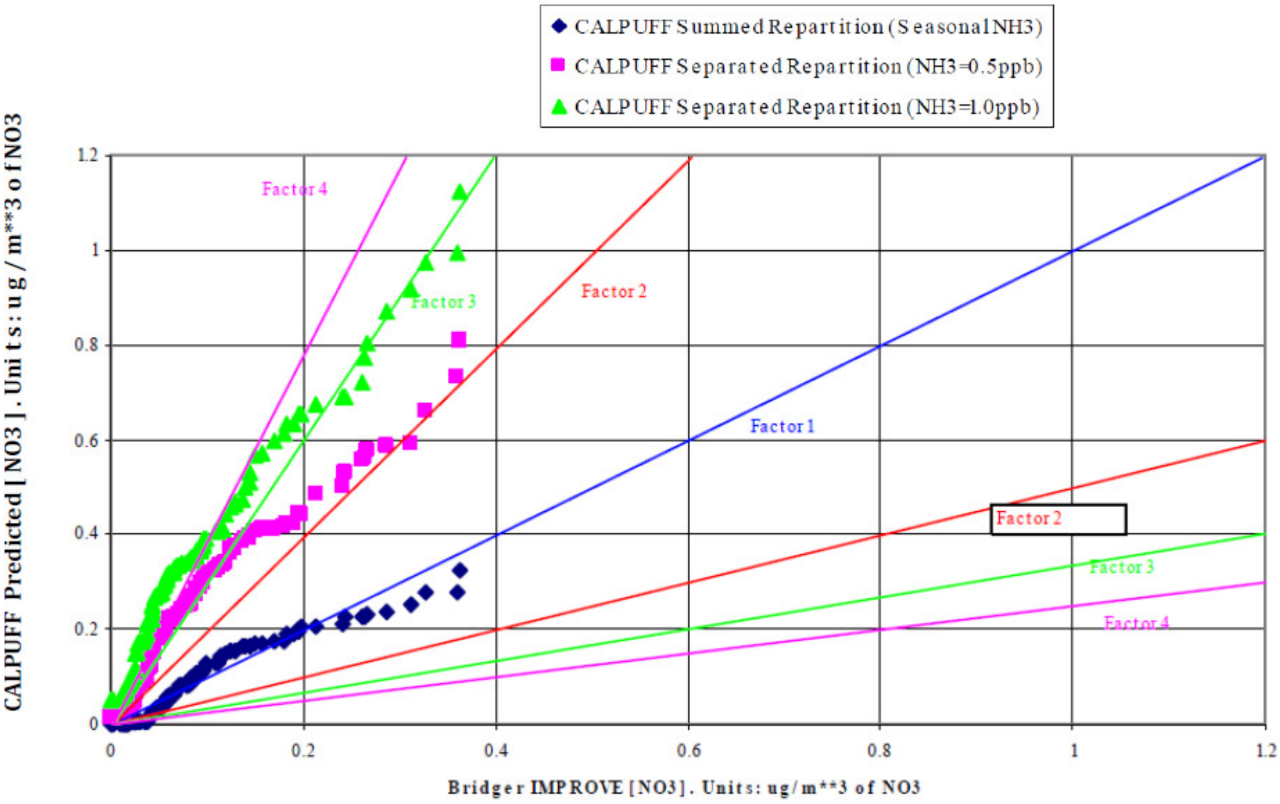
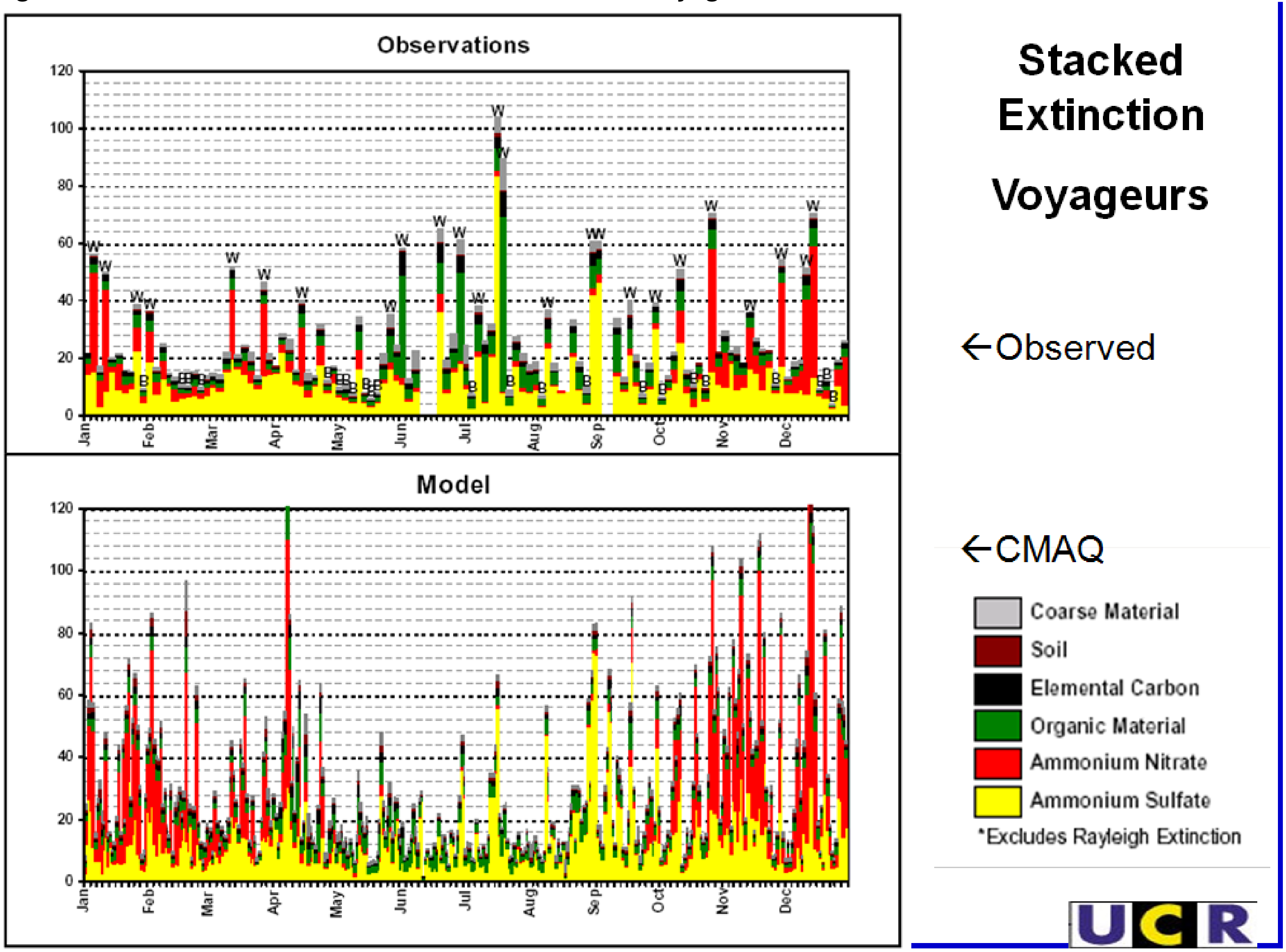


Figure B-4 CMAQ vs. Observed Haze Predictions at Voyageurs National Park



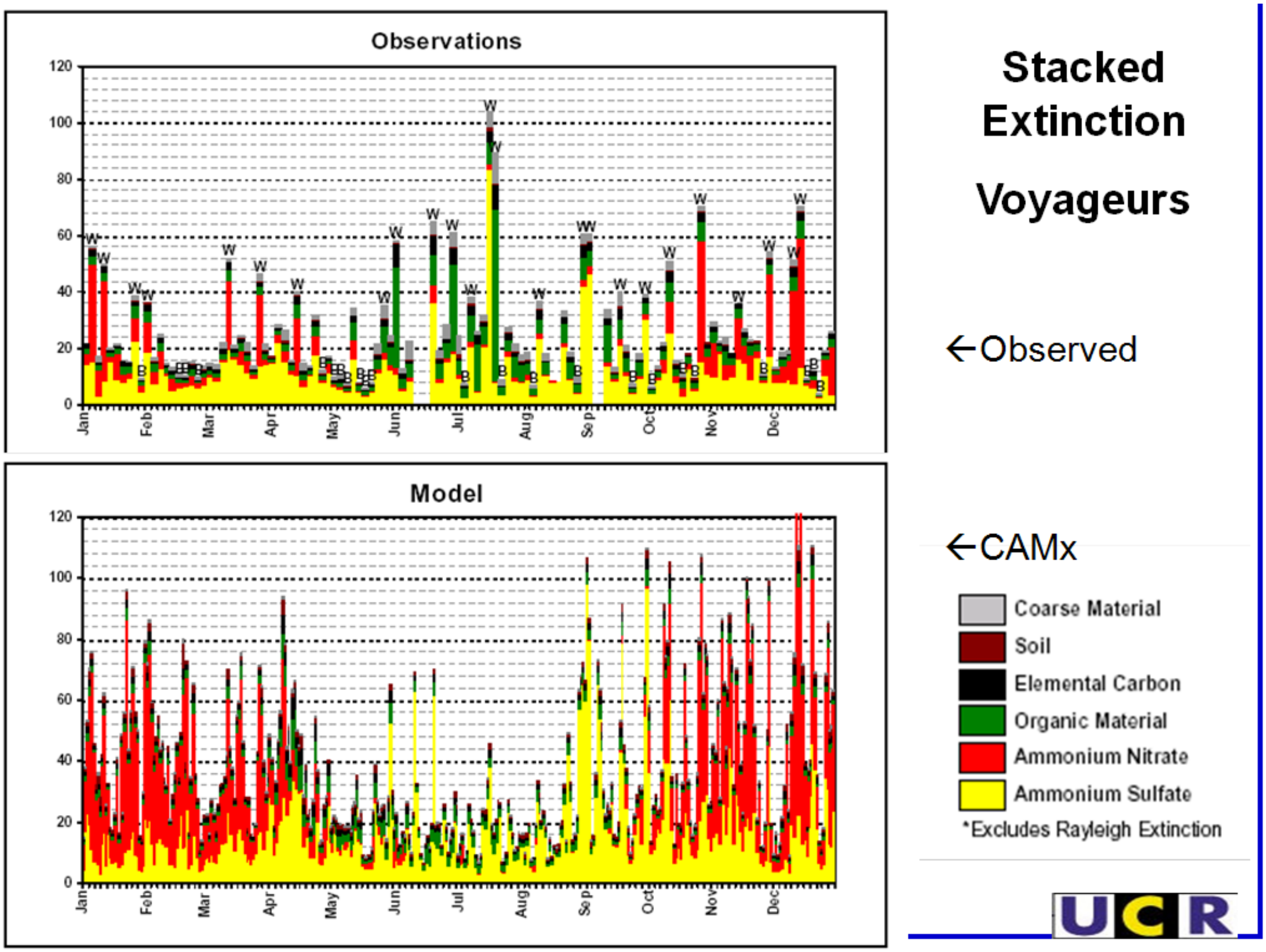
Stacked Extinction

Voyageurs

←Observed

←CMAQ

Figure B-5 CAMx vs. Observed Haze Predictions at Voyageurs National Park



APPENDIX C

Haze Time Series Plots for Voyageurs National Park, Seney Wilderness Area, and Isle Royale National Park

Figure C-1 Time Series of Nitrate Haze at Voyageurs National Park (2002-2010)

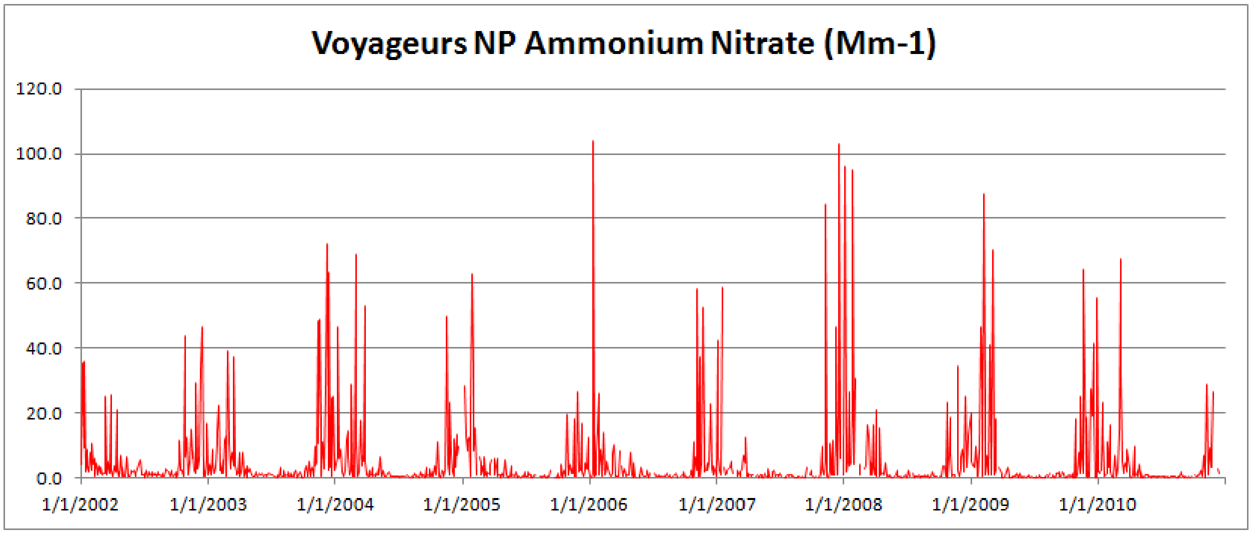


Figure C-2 Time Series of Sulfate Haze at Voyageurs National Park (2002-2010)

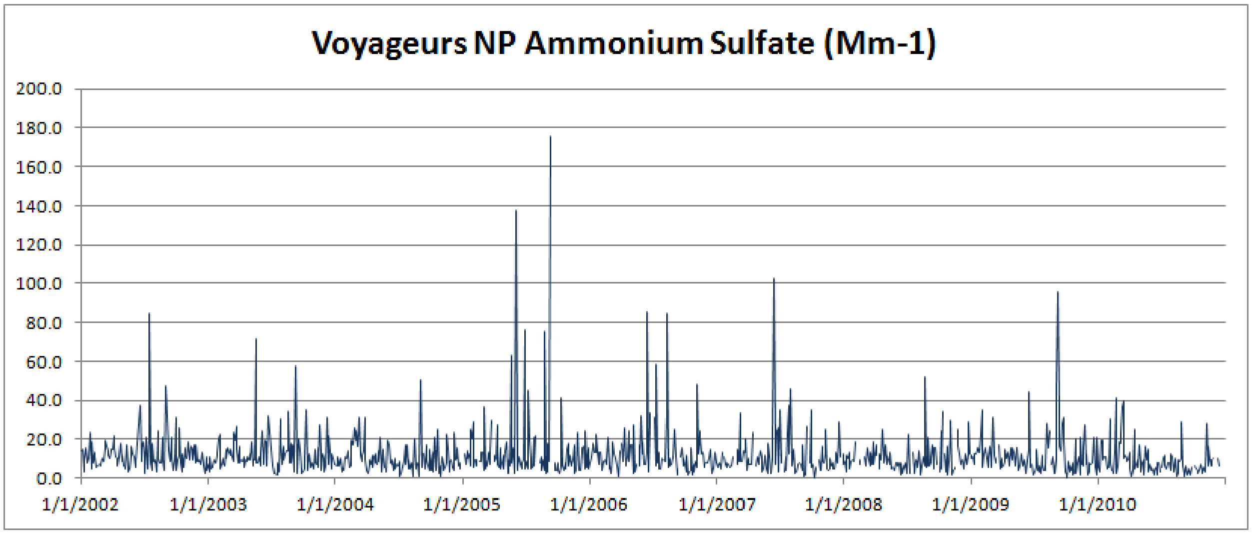


Figure C-3 Time Series of Nitrate Haze at Seney Wilderness Area (2002-2010)

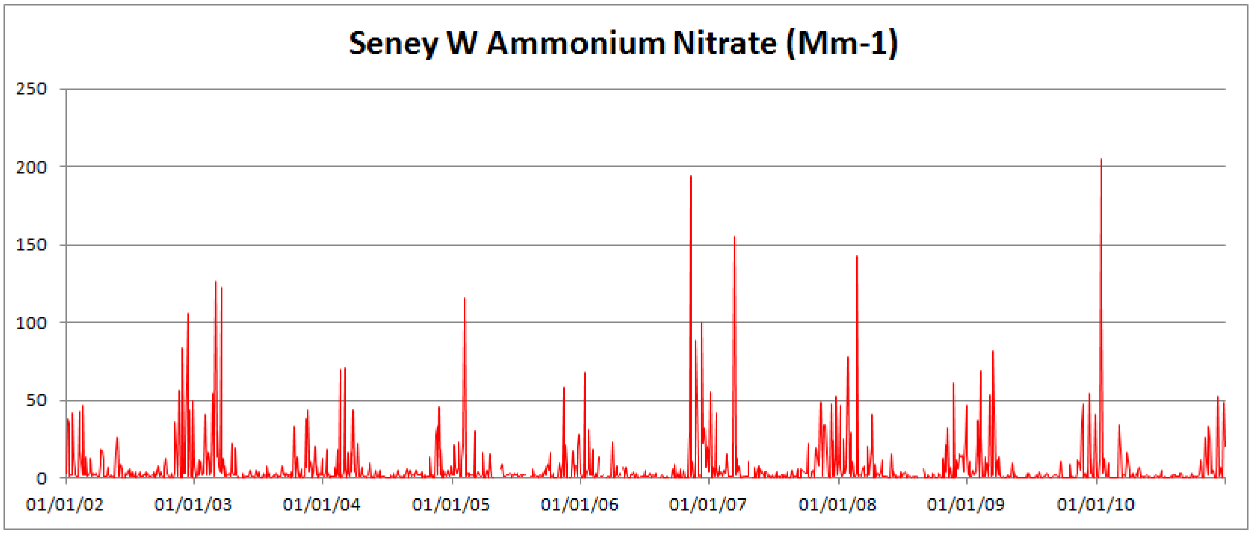


Figure C-4 Time Series of Sulfate Haze at Seney Wilderness Area (2002-2010)

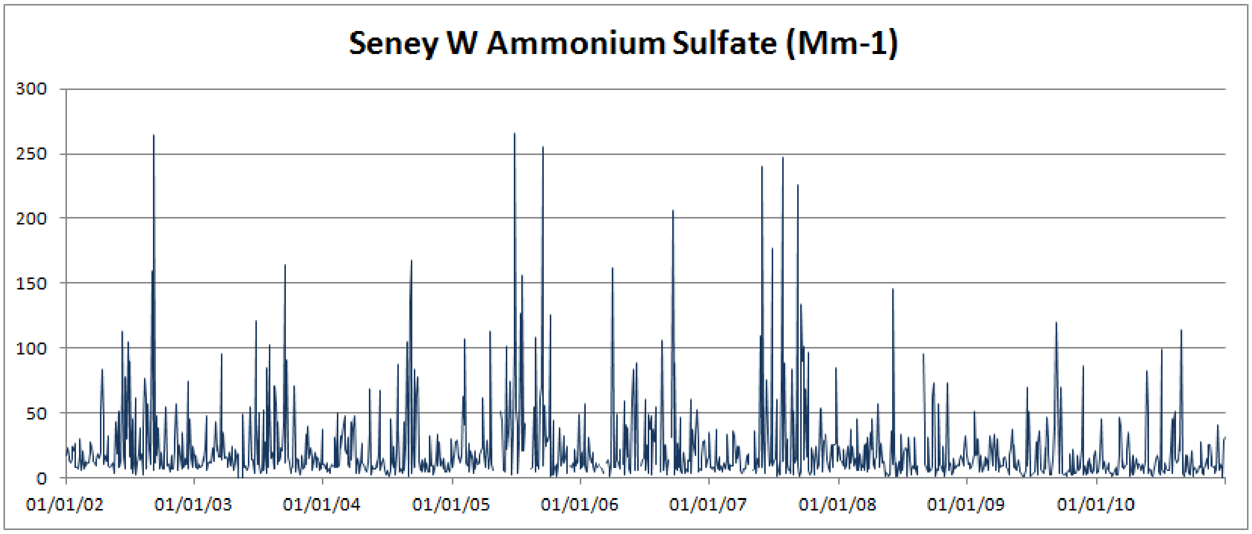


Figure C-5 Time Series of Nitrate Haze at Isle Royale National Park (2002-2010)

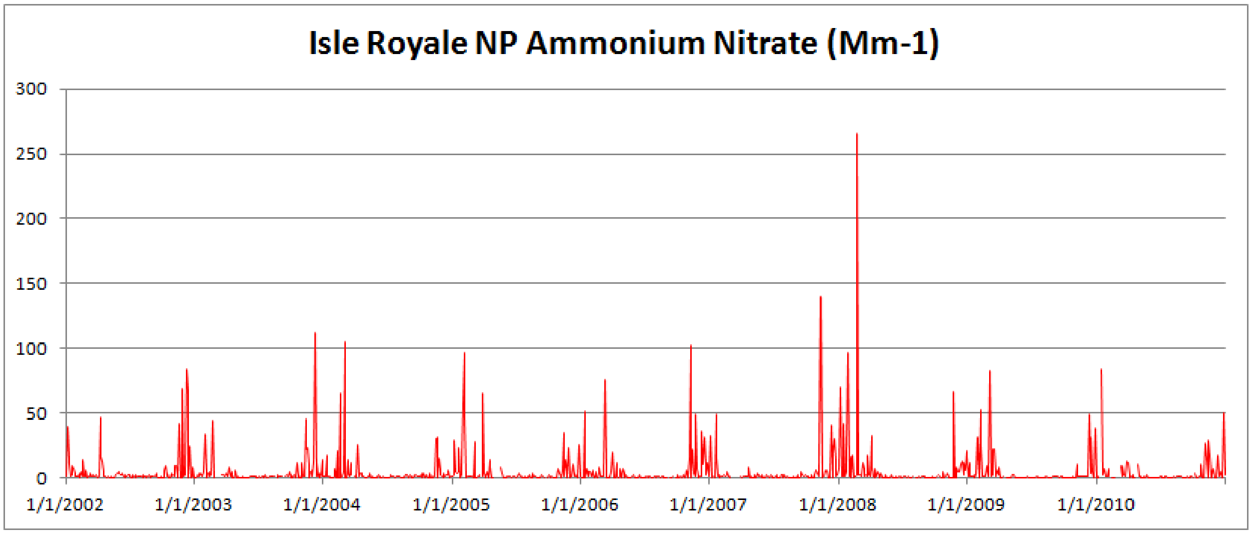
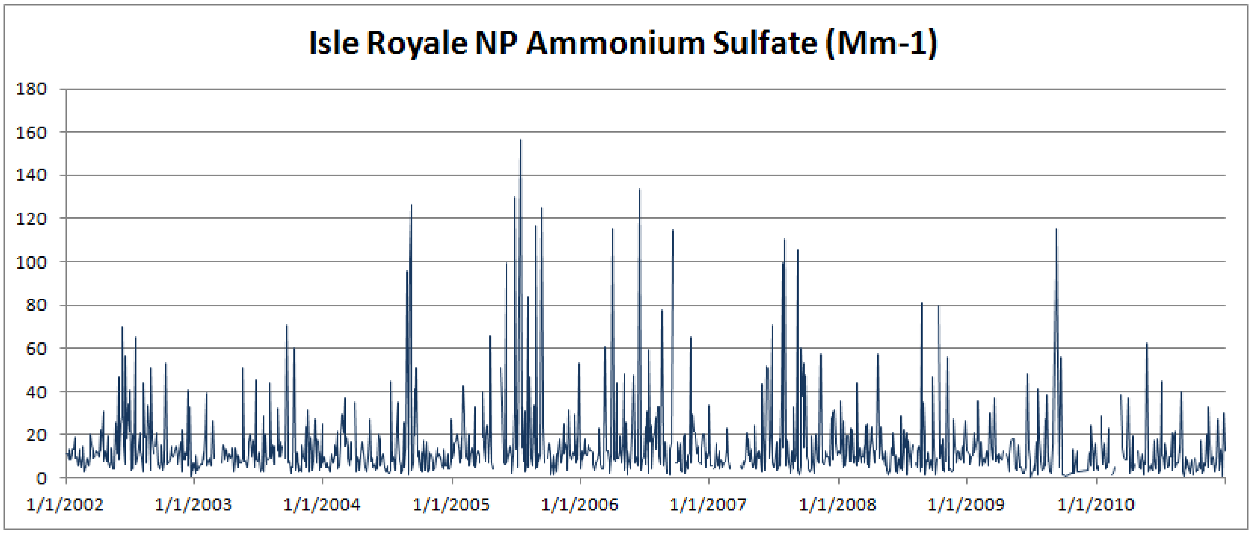


Figure C-6 Time Series of Sulfate Haze at Isle Royale National Park (2002-2010)



APPENDIX D

EXAMPLE OF VISIBILITY CHANGES AFTER ACTUAL EMISSION REDUCTIONS: SHUTDOWN OF THE MOHAVE GENERATING STATION

The Mohave Generating Station (MGS) shut down at the end of 2005, which should have had a large, beneficial effect (over 2 dv, according to CALPUFF) upon Grand Canyon visibility on the 98th percentile worst days. The MGS was a large (1590 MW) coal-fired plant located near the southern tip of Nevada (Laughlin, NV). MGS was placed in operation in the early 1970s, and was retired at the end of 2005 as a result of a consent agreement with the United States Environmental Protection Agency (EPA). The agreement had provided MGS with the option of continued operation if state-of-the-art emissions controls were installed for SO_2 and NOx emissions, but the owners determined that the cost of controls was too high to justify the investment. As a result, the plant was shut down on December 31, 2005 and has not been in operation since then.

As shown in Figure C-1, the MGS location is about 115 km away from the closest point of the Grand Canyon National Park, for which a southwesterly wind is needed to carry the emissions from MGS to most of the park. A multi-year study[39] completed by the EPA in 1999 (Project MOHAVE) indicated that MGS could be a significant contributor to haze in the Grand Canyon. In fact, typical annual emissions from MGS during the last several years of operation were approximately 40,000 tons per year (TPY) of SO_2 and 20,000 TPY of NOx. EPA noted in their Project MOHAVE conclusions that due to this level of emissions of haze precursors and its proximity to the Grand Canyon, MGS was the single largest emission source that could cause regional haze within the Grand Canyon.

Haze observations at three locations in the Grand Canyon (Meadview, Indian Garden, and Hance Camp monitors are available every third day for periods both before and after the plant shut down at the end of 2005. By comparing haze measurements before and after plant shutdown, it may be possible to determine whether the haze in the Grand Canyon has perceptibly changed since 2005 by reviewing the data from these three monitors. The Meadview monitor is at the western edge of the Park, and is relatively close to MGS. The other two IMPROVE monitors are located near some of the most heavily visited areas of the park (Hance Camp, on the South Rim, and Indian Garden, about 1,100 feet lower near the bottom of the canyon).

A 2010 *Atmospheric Environment* paper by Terhorst and Berkman[40] studied the effects of the opportunistic “experiment” afforded by the abrupt shutdown of the largest source affecting the Grand Canyon (according to EPA). The paper noted that Project MOHAVE’s conclusions about the effects of MGS on the Grand Canyon visibility were ambiguous. The project’s tracer studies revealed that while the MGS emissions did reach the park, particularly in the summer, there was no evidence linking these elevated concentrations with actual visibility impairment; indeed, “correlation between measured tracer concentration and both particulate sulfur and light extinction were virtually nil.”

On the other hand, dispersion models produced results inconsistent with the observations. Noting the disconnect between the measurements and model predictions, EPA noted the disparity between the measurements and modeling results, but still appeared to favor the models when it concluded that MGS was the largest sole contributor to visibility impairment in the Grand Canyon.

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[39] Pitchford, M., Green, M., Kuhns, H., Scruggs, M., Tombach, I., Malm, W., Farber, R., Mirabella, V., 1999. Project MOHAVE: Final Report. Tech. Rep., U.S. Environmental Protection Agency (EPA).

[40] Jonathan Terhorst and Mark Berkman. “Effect of Coal-Fired Power Generation on Visibility in a Nearby National Park,” Atmospheric Environment, 44(2010) 2544-2531. This publication is available by request from Mark Berkman at mark.berkman@berkeleyeconomics.com.

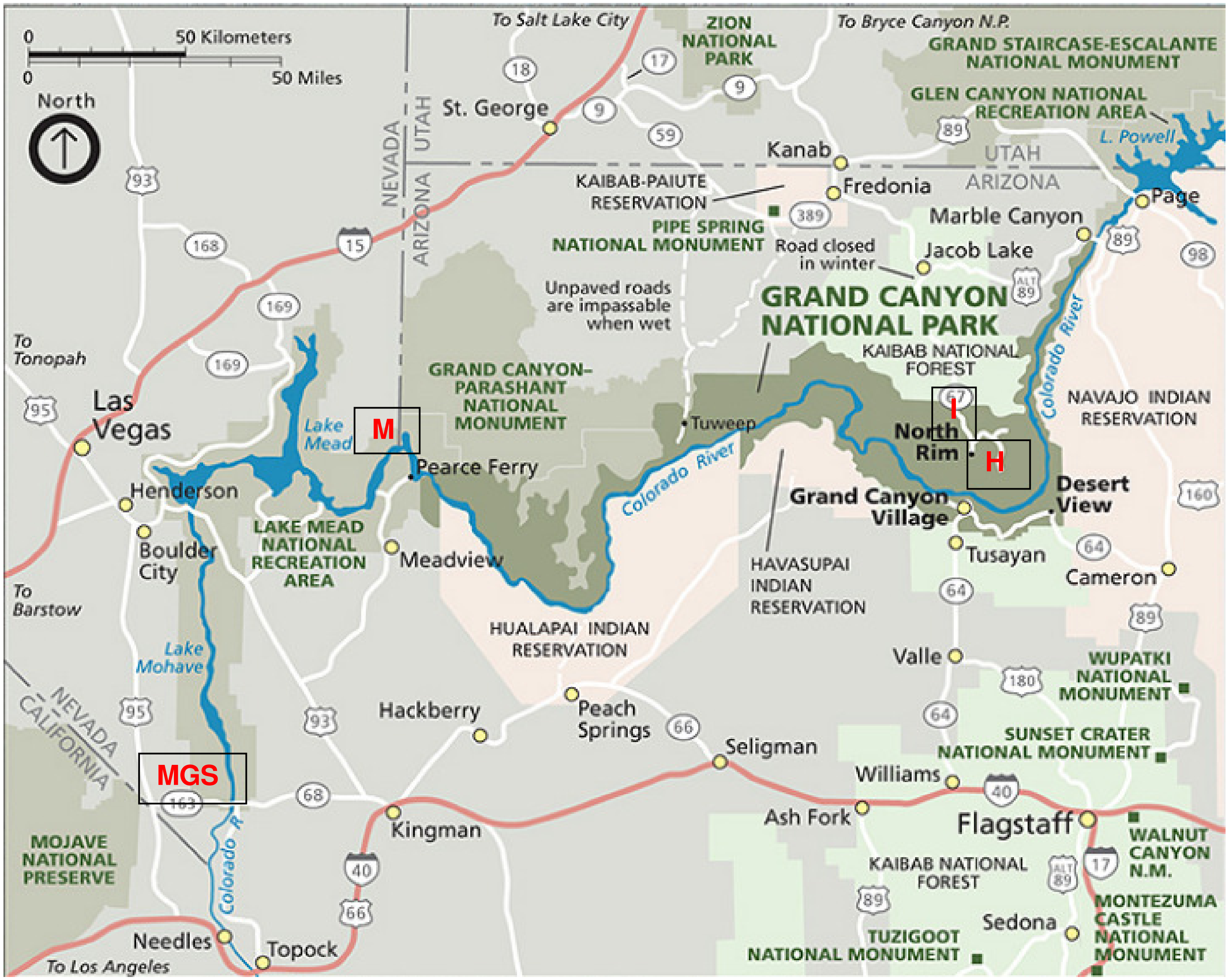
According to the authors, the Project Mohave observations were consistent with observations during temporary outages of MGS, for which there were no reports of substantial changes to visibility in the Grand Canyon.

Best Available Retrofit Technology (BART) studies evaluated a possible conversion of MGS to natural gas firing in 2008. These studies used the CALPUFF dispersion model in a manner prescribed by EPA to determine the change in visibility between the baseline emissions associated with coal firing to the natural gas firing alternative. The BART analyses conducted by the Nevada Department of Environmental Protection indicated that large differences in haze would result: an improvement of about 2.4 deciviews for the 98th percentile peak day, and a haze reduction to below 0.5 deciview on 186 days over 3 years modeled. Since natural gas firing would eliminate nearly all of the SO_2 emissions (although not all of the NOx emissions) this modeled result would tend to underestimate the visibility improvement that would be anticipated with a total plant shutdown.

Terhorst and Berkman analyzed several statistics to determine the change in sulfate concentrations and visibility in the Grand Canyon between the period 2003-2005 (pre-shutdown) and the period 2006-2008 (post-shutdown). They also considered other areas to determine how other regional and environmental effects might be reflected in changes at the Grand Canyon. Terhorst and Berkman calculated the average visibility over all IMPROVE monitoring days between 2003-2005 and 2006-2008, and determined that the average visibility was unchanged at Meadview, slightly improved on the South Rim (Hance Camp), and slightly worse at Indian Garden. Consistent with the observations of minimal visibility impact of MGS during Project MOHAVE, they concluded that the closure of MGS had a relatively minor effect on visibility in the Grand Canyon. These authors questioned the veracity of CALPUFF modeling (e.g., for BART) in that it predicts relatively large improvements in the Grand Canyon visibility that are not borne out by observations.

Emissions reductions associated with the shutdown of the Mohave Generating Station at the end of 2005 have provided an opportunistic means to discern the effect of retrofitting emission controls on coal-fired power plants in the western United States. In the case of MGS, although EPA had determined that this facility was the single most important contributor to haze in the Grand Canyon National Park and CALPUFF modeling using EPA's BART procedures provided predictions of significant improvements in haze, actual particulate and haze measurements taken before and after the shutdown do not reflect the large reductions that would be anticipated from these studies. This may be due in part to the fact that there are several aspects to the CALPUFF modeling procedures that greatly inflate the predicted haze (as noted below), and therefore, the predicted improvements due to emission reductions.

Figure D-1 : Map Showing the Relationship of the Mohave Generating Station to the Grand Canyon National Park



http://www.nps.gov/grca/planyourvisit/upload/GRCAmap2.pdf

H: Hance Camp monitor

I: Indian Garden monitor

M: Meadview monitor

From: Zavoda, Rich
To: Bouchareb, Hassan (MPCA); Seelen, Sarah (MPCA)
Cc: Johnson, Jaime; Peterson, Robb A; Machinal, Mandy L; Latendresse, Edward M; Lucas, Julie C; Niemi, Tasha M; Ekholm, Corie A; Ryan D. Siats; Kurdila, Julianne; Zavoda, Rich
Subject: FW: Minnesota Regional Haze Update :: Source Selection & Four Factor Analysis :: ArcelorMittal Minorca and Hibbing Taconite Company
Date: Wednesday, July 1, 2020 12:43:50 PM
Attachments: MPCA NOx SOx 2016 2028 w Corrected NOx 2028 for LNBs installed 7.1.20.xlsx
Minorca Mine SO2 Limit Revision for FIP 4.6.2018.pdf
4.11.18 HTC FIP SO2 Limit Reset Request.pdf
RE Regional Haze ArcelorMittal (HibbingMinorca) Four Factor Analyses H. Bouchareb x2653 Post.msg

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Hassan

As a follow-up to the Hibbing and Minorca "Four Factor Analysis" Reports submitted to MPCA on 5/29/20 and our request that both facilities be considered "Effectively Controlled" based on the newly engineered site specific Low NOx Burner Technology that has already been installed on all four natural gas pellet lines as discussed during our 6/12/20 conference call, please see the attached documentation of the reduction of NOx emissions.

The attached excel file provides requested NOx reduction data analysis and production records in three worksheets. The attached data provides the MPCA proposed 2016 Baseline and 2028 projections of NOx and SO2 tpy estimates that need to be corrected to account for the NOx reduction technology already installed on all four lines (Hibbing's 3 lines and Minorca's furnace). The data analysis also provide the 2017 NOx and SO2 tpy emissions based on a full year of CEMs data and is recommended to be used as a more accurate baseline compared to the 2016 estimates. The data highlights the incorrect NOx data in red font and uses blue font for the recommended 2017 Baseline and Corrected 2028 projections of NOx and SO2 tpy estimates. The corrected data is requested to be used for any LADCO modeling.

Per your request, the SO2 CEMs 95 percentile Upper Predictive Limit (UPL) statistical analysis reports as specified by the BART FIP requirements are attached. The reports for the natural gas fired indurating furnaces are dated 4/6/18 for Minorca and 4/11/18 for Hibbing. These reports that were submitted to USEPA provide the 95 UPL technical justification including one year of CEMs data for the respective SO2 lb/hr 30-day rolling average UPL rates referenced in the 5/29/20 "Four Factor Analysis" (page 21) for both facilities: 58.64 lb/hr for Minorca (see pdf pages 2 and 9) and 279.3 lb/hr for Hibbing (see pdf pages 3 and 4). The actual SO2 emissions from the natural gas fired pellet furnaces at Minorca and Hibbing have consistently complied with the respective lb/hr 30 day average 95 UPL rates referenced in the May 29, 2020 "Four Factor Analysis" reports.

Please let us know if you have any questions or would like to discuss. We look forward to the agency's response to our 5/29/20 Four Factor Analysis" Reports. Thanks again for your assistance with this important issue.

Rich Zavoda | Regional Manager, Air Quality Program
ArcelorMittal USA
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From: Johnson, Jaime <Jaime.Johnson@arcelormittal.com>
Sent: Tuesday, June 2, 2020 2:09 PM
To: Bouchareb, Hassan (MPCA) <hassan.bouchareb@state.mn.us>
Cc: Zavoda, Rich <Rich.Zavoda@arcelormittal.com>; Peterson, Robb A <robb.peterson@arcelormittal.com>; Machinal, Mandy L <mandy.machinal@arcelormittal.com>; Latendresse, Edward M <edward.latendresse@arcelormittal.com>; Lucas, Julie C <julie.lucas@arcelormittal.com>; Niemi, Tasha M <tasha.niemi@arcelormittal.com>; Ryan D. Siats <RSiats@barr.com>

Subject: RE: Minnesota Regional Haze Update :: Source Selection & Four Factor Analysis :: ArcelorMittal Minorca

Hassan,

Good morning. ArcelorMittal Hibbing and Minorca facilities, (facilities) received MPCA's Request for Information letter dated January 29, 2020. This letter requested the facilities prepare a Four Factor Analysis for the indurating machine(s). These analyses are to be prepared using the August 20, 2019 U.S. Environmental Protection Agency guidance that provides recommendations for how each of the factors should be analyzed. However, the Guidance also provides flexibility to the state such that states are not required to evaluate *all* sources of emissions in each implementation period. Instead, a state may select a set of sources for analysis of control measures and reasonably exclude others from the analysis.

The facilities' indurating machine(s) meet the BART required control equipment scenarios and are effectively controlled source(s) for NOx and SO2. BART emission controls and emission limits for NOX and SO2 are determined pursuant to 40 CFR 52.1235(b)(1) and 52.1235(b)(2), respectively. In accordance with the April 12, 2016 FIP, the Facilities timely implemented the BART NOx control measures by installing and operating newly engineered site-specific Low NOx Burner technology on all four pellet lines (three at Hibbing and one at Minorca) prior to the required FIP compliance dates with three of the four lines completing installation in 2020. The indurating machines are subject to the FIP NOx emission limits as defined in the FIP. The indurating furnace Low NOx Burners recently installed have reduced the majority of the NOx emissions. In the FIP preamble, U.S. EPA concluded that BART for SO2 emissions from these natural gas fired lines, already equipped with Taconite MACT wet scrubbers, is existing controls. Thus, each of the indurating machines is considered an "effectively controlled source" in accordance with the 2019 U.S. EPA Guidance and may be reasonably excluded from the requirement to prepare and submit a four-factor analysis.

ArcelorMittal would like to request a call with you to discuss the submitted report which indicates that the sources at the Facilities are effectively controlled for the purpose of this implementation period. Understanding that this process is time sensitive for the MPCA and the Facilities, ArcelorMittal prefers to have this call with representatives from ArcelorMittal USA, Minorca, Hibbing and Barr Engineering. We are proposing the following date/times for a call:

Availability

Monday 6/8/2020	12:00pm-1:00pm
Tuesday 6/11/2020	11:00am – 12:00pm
	2:00pm-3:00pm
Friday 6/12/2020	10:00 – 11:00am
	12:00-1:00pm

I thank you for your time and consideration of this request. I look forward to hearing from you in the near future to further our discussions on the request submitted on the 29th of May.

Thank you,
Jaime

Jaime L. Johnson
Manager - Environmental

ArcelorMittal Minorca Mine Inc.
5950 Old U.S. Highway 53 | Virginia, MN 55792
T +1 218 305 3337 | F +1 218 749 5256
www.arcelormittal.com

"Wrinkles only go where the smiles have been" – Jimmy Buffett

"Happiness cannot be traveled to, owned, earned, worn, or consumed. Happiness is a spiritual experience of living every minute with love, grace, and gratitude" - Dennis Waitley

"I believe that imagination is stronger than knowledge - myth is more potent than history - dreams are more powerful than facts - hopes always triumphs over experience - laughter is the cure for grief - love is stronger than death" - Robert Fulghum

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From: Bouchareb, Hassan (MPCA) <hassan.bouchareb@state.mn.us>
Sent: Friday, May 29, 2020 12:46 PM
To: Machinal, Mandy L <mandy.machinal@arcelormittal.com>
Cc: Seelen, Sarah (MPCA) <sarah.seelen@state.mn.us>; deAlwis, Deepa (MPCA) <deepa.dealwis@state.mn.us>; Boeck, Cory (MPCA) <cory.boeck@state.mn.us>; Kohlasch, Frank (MPCA) <frank.kohlasch@state.mn.us>; Zavoda, Rich <Rich.Zavoda@arcelormittal.com>; Peterson, Robb A <robb.peterson@arcelormittal.com>; Johnson, Jaime <Jaime.Johnson@arcelormittal.com>
Subject: RE: Minnesota Regional Haze Update :: Source Selection & Four Factor Analysis :: ArcelorMittal Minorca

Good afternoon Mandy,

Thank you for sending this information. I'll review the response and let you know if I have any questions.

Thank you!

Hassan M. Bouchareb | Engineer
Minnesota Pollution Control Agency (MPCA)
Office: (651) 757-2653 | Fax: (651) 296-8324
Pronouns: he/him/his
Hassan.Bouchareb@state.mn.us | www.pca.state.mn.us

From: Machinal, Mandy L <mandy.machinal@arcelormittal.com>
Sent: Friday, May 29, 2020 12:25 PM
To: Bouchareb, Hassan (MPCA) <hassan.bouchareb@state.mn.us>
Cc: Seelen, Sarah (MPCA) <sarah.seelen@state.mn.us>; deAlwis, Deepa (MPCA) <deepa.dealwis@state.mn.us>; Boeck, Cory (MPCA) <cory.boeck@state.mn.us>; Kohlasch, Frank (MPCA) <frank.kohlasch@state.mn.us>; Zavoda, Rich <Rich.Zavoda@arcelormittal.com>; Peterson, Robb A <robb.peterson@arcelormittal.com>; Johnson, Jaime <Jaime.Johnson@arcelormittal.com>
Subject: Minnesota Regional Haze Update :: Source Selection & Four Factor Analysis :: ArcelorMittal Minorca

---

Good Afternoon –

Please see Minorca's attached response to MPCA's request for information for the Four Factor Analysis. We look forward to MPCA's timely response on this submittal.

Thank you,
Mandy Machinal

Mandy Machinal | Engineer - Environmental
ArcelorMittal Minorca
Iron Mining | 5950 Old U.S. Highway 53 | PO Box 1
Virginia, MN 55792 USA

T +1 218-305-3425 **|** **F** +1 218 749 3397 | **E** Mandy.Machinal@arcelormittal.com

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January 29, 2020

Melissa Weglarz
Minnesota Power - Boswell Energy Center
1210 3rd Street NW
Cohasset, MN 55721

RE: Request for Information - Regional Haze Rule, Reasonable Progress, Four Factor Analysis

Dear Ms. Weglarz:

The Minnesota Pollution Control Agency (MPCA) is currently preparing information for the second planning period (Round 2) comprehensive update to Minnesota's Regional Haze State Implementation Plan (SIP) as required by the Regional Haze Rule (40 CFR § 51.308). States are responsible for developing a Regional Haze SIP that addresses regional haze in each Class I area located within the state and in each Class I area located outside the state which may be affected by emissions from sources within the state. The Regional Haze SIP is required to identify existing facilities that cause or contribute to visibility impairment; analyze, identify, and apply federally-enforceable control strategies for those sources; and periodically demonstrate reasonable progress toward reaching visibility goals. States are also responsible for periodic comprehensive updates to their Regional Haze SIP that address these same topics. Minnesota's Round 2 Regional Haze SIP must be submitted to the U.S. Environmental Protection Agency (U.S. EPA) by July 31, 2021.

Minnesota has two Class I areas within its borders, the Boundary Waters Canoe Area Wilderness (BWCA) and Voyageurs National Park (Voyageurs). Other nearby Class I areas include Isle Royale National Park in Michigan. Therefore, Minnesota must prepare a Regional Haze SIP that identifies sources that cause or contribute to visibility impairment in these areas. To meet the core requirements for regional haze for these areas, Minnesota must submit a SIP that contains the plan elements and supporting documentation for all required analyses identified in 40 CFR § 51.308(f).

In the first planning period (Round 1), the focus of the Regional Haze Rule was on establishing Best Available Retrofit Technology (BART) for certain older sources and reasonable progress towards national visibility goals. In Round 2, there are no BART requirements; therefore, the focus is on making reasonable progress. The U.S. Environmental Protection agency has defined the methodology that states must use to determine what measures are necessary to make reasonable progress in 40 CFR § 51.308(f)(2). At minimum, the reasonable progress analysis must use the four factors identified in 40 CFR § 51.308(f)(2)(i) to evaluate and determine the emission reduction measures necessary to make reasonable progress. The four factors are:

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

Data from the IMPROVE monitoring sites at BWCA and Voyageurs indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X).

You are receiving this letter because your facility was identified as a significant source of NO_X and SO_2 and is located close enough to the BWCA or Voyageurs to potentially cause or contribute to visibility impairment in these Class I areas. Therefore, the MPCA requests that you prepare a "Four Factor Analysis" for the following emission units:

1. Unit 1 - Wall fired dry bottom (EQUI 82 / EU 001) that addresses emissions of NO_X and SO_2
2. Unit 2 - Wall fired dry bottom (EQUI 83 / EU 002) that addresses emissions of NO_X and SO_2
3. Unit 3 - Tangential fired (EQUI 100 / EU 003) that addresses emissions of NO_X and SO_2
4. Unit 4 - Tangential fired (EQUI 85 / EU 004) that addresses emissions of NO_X and SO_2

The analysis should be prepared using the U.S. Environmental Protection Agency guidance[1] that provides recommendations for how each of the factors should be determined.

Preparation of the comprehensive update to Minnesota's Regional Haze SIP will require extensive planning and review of sources in Minnesota. The MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to prepare the Regional Haze SIP. The MPCA expects air quality modeling of potential regional emissions reductions will be conducted beginning in spring 2020. I appreciate your attention to this matter and request that you **submit the Four Factor Analysis by July 31, 2020**.

If you have any questions regarding this matter, or would like to request a meeting to further discuss the contents of this letter, please contact me by phone at 651-757-2653 or by email at Hassan.Bouchareb@state.mn.us.

Sincerely,

Hassan Bouchareb

This document has been electronically signed.

Hassan M. Bouchareb
Engineer
Environmental Analysis and Outcomes Division

Cc: Kurt Anderson, Minnesota Power
Crystal Tokarczyk, Minnesota Power
Deepa de Alwis, MPCA
Cory Boeck, MPCA
Frank Kohlasch, MPCA
Agency Interest ID 2493

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[1] **U.S. Environmental Protection Agency.** *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 20, 2019, https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

Address questions and submittals requested above to:

Hassan M. Bouchareb
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Hassan.Bouchareb@state.mn.us

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January 29, 2020

Melissa Weglarz
Minnesota Power - Taconite Harbor Energy Center
8124 W Highway 61
Schroeder, MN 55613

RE: Request for Information - Regional Haze Rule, Reasonable Progress, Four Factor Analysis

Dear Ms. Weglarz:

The Minnesota Pollution Control Agency (MPCA) is currently preparing information for the second planning period (Round 2) comprehensive update to Minnesota's Regional Haze State Implementation Plan (SIP) as required by the Regional Haze Rule (40 CFR § 51.308). States are responsible for developing a Regional Haze SIP that addresses regional haze in each Class I area located within the state and in each Class I area located outside the state which may be affected by emissions from sources within the state. The Regional Haze SIP is required to identify existing facilities that cause or contribute to visibility impairment; analyze, identify, and apply federally-enforceable control strategies for those sources; and periodically demonstrate reasonable progress toward reaching visibility goals. States are also responsible for periodic comprehensive updates to their Regional Haze SIP that address these same topics. Minnesota's Round 2 Regional Haze SIP must be submitted to the U.S. Environmental Protection Agency (U.S. EPA) by July 31, 2021.

Minnesota has two Class I areas within its borders, the Boundary Waters Canoe Area Wilderness (BWCA) and Voyageurs National Park (Voyageurs). Other nearby Class I areas include Isle Royale National Park in Michigan. Therefore, Minnesota must prepare a Regional Haze SIP that identifies sources that cause or contribute to visibility impairment in these areas. To meet the core requirements for regional haze for these areas, Minnesota must submit a SIP that contains the plan elements and supporting documentation for all required analyses identified in 40 CFR § 51.308(f).

In the first planning period (Round 1), the focus of the Regional Haze Rule was on establishing Best Available Retrofit Technology (BART) for certain older sources and reasonable progress towards national visibility goals. In Round 2, there are no BART requirements; therefore, the focus is on making reasonable progress. The U.S. Environmental Protection agency has defined the methodology that states must use to determine what measures are necessary to make reasonable progress in 40 CFR § 51.308(f)(2). At minimum, the reasonable progress analysis must use the four factors identified in 40 CFR § 51.308(f)(2)(i) to evaluate and determine the emission reduction measures necessary to make reasonable progress. The four factors are:

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

Data from the IMPROVE monitoring sites at BWCA and Voyageurs indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X).

You are receiving this letter because your facility was identified as a significant source of NO_X and SO_2 and is located close enough to the BWCA or Voyageurs to potentially cause or contribute to visibility impairment in these Class I areas. Therefore, the MPCA requests that you prepare a “Four Factor Analysis” for the following emission units:

1. Boiler No. 1 (EQUI 64 / EU 001) that addresses emissions of NO_X and SO_2
2. Boiler No. 2 (EQUI 5 / EU 002) that addresses emissions of NO_X and SO_2

The analysis should be prepared using the U.S. Environmental Protection Agency guidance[1] that provides recommendations for how each of the factors should be determined.

Preparation of the comprehensive update to Minnesota’s Regional Haze SIP will require extensive planning and review of sources in Minnesota. The MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to prepare the Regional Haze SIP. The MPCA expects air quality modeling of potential regional emissions reductions will be conducted beginning in spring 2020. I appreciate your attention to this matter and request that you **submit the Four Factor Analysis by July 31, 2020**.

If you have any questions regarding this matter, or would like to request a meeting to further discuss the contents of this letter, please contact me by phone at 651-757-2653 or by email at Hassan.Bouchareb@state.mn.us.

Sincerely,

Hassan Bouchareb

This document has been electronically signed.

Hassan M. Bouchareb
Engineer
Environmental Analysis and Outcomes Division

Cc: Kurt Anderson, Minnesota Power
Cherese Johnson, Minnesota Power
Deepa de Alwis, MPCA
Cory Boeck, MPCA
Frank Kohlasch, MPCA
Agency Interest ID 1425

Address questions and submittals requested above to:

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Hassan.Bouchareb@state.mn.us

---

[1] **U.S. Environmental Protection Agency.** *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 20, 2019, https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

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June 1, 2020

Mr. Hassan M. Bouchareb
Environmental Analysis and Outcomes Division
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, Minnesota 55155-4194
Hassan.Bouchareb@state.mn.us

Re: Effectively Controlled Source Determination
MPCA Request for Information – Regional Haze Rule, Reasonable Progress, Four Factor Analysis
Minnesota Power's Bowell Energy Center (Title V Operating Permit No. 06100004-008)

Dear Mr. Bouchareb,

On January 29, 2020, the Minnesota Pollution Control Agency (MPCA) issued Minnesota Power (MP) a Regional Haze Rule Request for Information (RFI) for MP's Boswell Energy Center (BEC). The RFI requested that MP submit by July 31, 2020 a "Four Factor Analysis" for the following BEC emission units:

- Unit 1 – Wall-fired dry bottom (EQUI 82 / EU 001) that addresses emissions of NOx and SO_2
- Unit 2 – Wall-fired dry bottom (EQUI 83 / EU 002) that addresses emissions of NOx and SO_2
- Unit 3 – Wall-fired dry bottom (EQUI 100 / EU 003) that addresses emissions of NOx and SO_2
- Unit 4 – Wall-fired dry bottom (EQUI 85 / EU 004) that addresses emissions of NOx and SO_2

This letter is MP's response to the "Four Factor Analysis" request for BEC.

BEC Unit 1 (EQUI 82 / EU 001) and Unit 2 (EQUI 83 / EU 002)

BEC Units 1 and 2 were permanently retired and removed from the Acid Rain Permit (ARP) in December 2018. These two units are no longer legally permitted to operate per MP's state/federal Consent Decree and MPCA Title V Permit 06100004-008 (5.18.16 and 5.19.16) which mandated their retirement no later than December 31, 2018. Therefore a "Four Factor Analysis" is not required for BEC Unit 1 and 2.

MPCA was informed of MP's intent to not complete the RFI for the retired BEC units 1 and 2 units via electronic correspondence dated January 29, 2020. During this communication, you concurred that BEC 1 and 2 analysis was not necessary, and requested MP restate the circumstances within this submittal.

BEC Unit 3 (EQUI 100 / EU 003)

The MPCA specifies in the RFI that U.S. Environmental Protection Agency (USEPA) guidance[1] should be followed to complete a "Four Factor Analysis". This guidance document includes a discussion that states can reasonably exclude sources already equipped with effective emission controls from the requirement to conduct a "Four Factor Analysis" due to the likely conclusion of such an analysis being that no further controls are necessary[2]. The guidance document provides several examples of the types of emission controls that could be installed for a source to be considered "effectively controlled" while noting the examples are not an exhaustive list.

As noted in the following bullet points, BEC Unit 3 (BEC3) meets at least one of the "effectively controlled" source examples for both NO_X and SO_2 which excludes the source from the requirement to conduct a "Four Factor Analysis":

- **NO_X** – One example of an "effectively controlled" emission source included in USEPA's guidance document is a BART-eligible emission unit that "*installed and began operating controls to meet BART emission limits for the first implementation period*."[3] The Technical Support Document (TSD) for BEC's Title V Operating Permit that was issued on March 28, 2007 (No. 06100004-003) specifies that BEC3 would install low-NO_X burners, over-fire air, and selective catalytic reduction[4] to control NO_X emissions. One of the justifications for the installation of this control equipment, among others, is the Regional Haze Rule. As noted on page 12 of the Technical Support Document (TSD)[5] for BEC's Title V Operating Permit (No. 06100004-008), BEC3's NO_X BART limit was later replaced with BEC3's more restrictive Consent Decree limit[6]. As such, BEC Unit 3 meets this example, and is "effectively controlled" for NO_X as defined in USEPA's guidance document.

- **SO_2** – Another example of an "effectively controlled" emission source included in USEPA's guidance document is an electric generating unit (EGU) with flue gas desulfurization (FGD) and

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[1] USEPA, *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 20, 2019.
[2] Ibid, Pages 22-25.
[3] Ibid, Page 25.
[4] Controls identified as TREA 5 and TREA 8 in the facility's current Title V Operating Permit No. 06100004-008.
[5] Technical Support Document to Permit No. 06100004-008, Page 12 of 71
[6] Case No.: 0:14-cv-02911-ADM-LIB, https://www.epa.gov/sites/production/files/2014-07/documents/minnesotapower-cd.pdf

that meets the applicable alternative SO_2 emission limit of the 2012 Mercury Air Toxics Standards (MATS) Rule. USEPA states that for a source of this type "*… [it] is unlikely […] that even more stringent control of SO_2 is necessary to make reasonable progress.*"[7] BEC3 is an EGU equipped with wet FGD (TREA 10) and is currently complying with the alternative SO_2 emission limit of the MATS Rule. BEC3 therefore meets the example scenario of USEPA's guidance document and is considered "effectively controlled" for SO_2.

BEC Unit 4 (EQUI 85 / EU 004)

Following the same EPA guidance used for BEC3 above, BEC Unit 4 (BEC4) meets at least one of the "effectively controlled" source examples for both NO_X and SO_2 which excludes the source from the requirement to conduct a "Four Factor Analysis":

- **NO_X** – Another example of an "effectively controlled" emission source included in USEPA's guidance document is a source that has completed a best available control technology (BACT) or lowest achievable emission rate (LAER) review and received a construction permit on or after July 31, 2013. Although not explicitly stated in the USEPA's guidance document, it may then be also reasonably assumed that a source would be considered "effectively controlled" if the current control technologies and their effectiveness are *equivalent or sufficiently similar to the control technologies for similar sources that did undergo a more recent BACT or LAER review*. A source should also be considered as "effectively controlled" if the source's existing permit limits, independent of statutory basis, are *consistent or sufficiently similar to recent best BACT or LAER determinations completed for similar sources*. MP believes these are valid assumptions because it is unlikely that additional controls would be necessary if the source already operates with BACT/LAER equivalent controls and/or emission limits, especially if those limits are stringent and Consent Decree-based as in the case of the MP Boswell units. In many cases, recent Air Quality Consent Decree limits are equivalent to or lower than BACT limits.

  A search of the USEPA's RACT/BACT/LAER Clearinghouse[8] (RBLC) in May 2020 revealed there have been no NOx BACT or LAER determinations entered into the database for coal-fired utility

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[7] USEPA, *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 20, 2019, Page 23.

[8] https://cfpub.epa.gov/rblc/index.cfm?action=Home.Home&lang=en

boilers with a maximum firing rate of greater than 250 MMBtu/hr since July 31, 2013[9] (the date specified by the USEPA's guidance document). However, extending the start date of the RBLC search back to January 1, 2010 shows several NO_X BACT evaluations between January 1, 2010 and July 31, 2013[10]. Although, BEC4 has not undergone a BACT or LAER review for NO_X at any time, the current BEC4 NO_X limit (0.12 lb NO_X/MMBtu) is much more stringent than these most recent RBLC-listed NO_X BACT evaluations (0.24 – 0.25 lb/MMBtu) for tangentially-fired coal boilers[11].

To achieve this NOx limit, BEC4 is equipped with existing NO_X control equipment, consisting of low-NO_X burners with separated over fire air and ROTA-Mix Selective Non-Catalytic Reduction[12]. These controls are consistent with other BACT determinations for all types of coal-fired boilers, not just tangentially-fired units, identified in the RBLC search[13]. As such, BEC Unit 4 should be considered "effectively controlled" for NO_X, based on the USEPA's guidance document which references "*…effective controls in place … to meet another CAA requirement*"[14].

- **SO_2** – Similar to BEC3, BEC4 is an EGU equipped with semi-dry FGD (TREA 21) and utilizes the MATS Rule alternative SO_2 emission limit compliance demonstration option. BEC4 is therefore "effectively controlled" for SO_2 as defined in USEPA's guidance document [an electric generating unit (EGU) with flue gas desulfurization (FGD) and that meets the applicable alternative SO_2 emission limit of the 2012 Mercury Air Toxics Standards (MATS) Rule]. Again, USEPA states that for a source of this type "*… [it] is unlikely […] that even more stringent control of SO_2 is necessary to make reasonable progress.*"[15]

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[9] Search of RBLC conducted for process type "*11.110 – Coal (includes bituminous, subbituminous, anthracite, and lignite)*", pollutant name "NOx", and date range of 07/31/2013 to 05/14/2020.
[10] The same search of the RBLC was conducted, except the date range was changed to 01/01/2010 to 07/31/2013.
[11] See BACT evaluations for Navajo Generating Station (AZ-0055), and Limestone Electric Generating Station (TX-0557), which specify limits of 0.24 and 0.25 lb NO_X/MMBtu, respectively.
[12] Controls identified as TREA 6 and TREA 7 in the facility's current Title V Operating Permit No. 06100004-008.
[13] See BACT evaluations for Navajo Generating Station (AZ-0055), Wolverine Power (MI-0400), and Minnkota Power Cooperative (ND-0026) for examples of similar controls accepted as BACT.
[14] USEPA, *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 20, 2019, Page 22.
[15] Ibid. Page 23.

Conclusion

Two of the emission units identified in MPCA's RFI, Unit 1 (EQUI 82 / EU 001) and Unit 2 (EQUI 83 / EU 002), have been retired and therefore a four-factor analysis is not necessary for these sources.

The other two emission units, Unit 3 (EQUI 100 / EU 003) and Unit 4 (EQUI 85 / EU 004), are "effectively controlled" for NO_X and SO_2 per the USEPA guidance and do not require a four-factor analysis.

Minnesota Power trusts this submittal fulfills the MPCA Regional Haze RFI for the Boswell Energy Center units. Please contact me if you have questions or require additional information.

Sincerely,

Melissa S. Weglarz

Melissa Weglarz
Environmental Audit & Policy Manager
Minnesota Power Environmental & Land Mgmt.
mweglarz@mnpower.com
Mobile: 218-343-0927

Enclosure: RBLC Search for NO_X BACT and LAER Determinations from Coal-Fired Utility Boilers

Minnesota Power - Boswell Energy Center
Regional Haze RFI
Coal-Fired Utility Boiler NOx RBLC Search

Pollutant Name: NO_X

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2
AZ-0055	NAVAJO GENERATING STATION	SALT RIVER PROJECT AGRICULTURAL AND POWER DISTRICT	AZ	AZ 08-01	221112	02/06/2012 ACT	2,250 MW COAL FIRED POWER PLANT	PULVERIZED COAL FIRED BOILER	COAL	7725	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNER (LNB), SEPARATED OVERFIRE AIR (SOFA) SYSTEM,	0.24	LB/MMBTU	30-DAY ROLLING AVG	BACT-PSD			
AZ-0055	NAVAJO GENERATING STATION	SALT RIVER PROJECT AGRICULTURAL AND POWER DISTRICT	AZ	AZ 08-01	221112	02/06/2012 ACT	2,250 MW COAL FIRED POWER PLANT	PULVERIZED COAL FIRED BOILER	COAL	7725	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNER (LNB), SEPARATED OVERFIRE AIR (SOFA) SYSTEM,	0.24	LB/MMBTU	30-DAY ROLLING AVG	BACT-PSD			
AZ-0055	NAVAJO GENERATING STATION	SALT RIVER PROJECT AGRICULTURAL AND POWER DISTRICT	AZ	AZ 08-01	221112	02/06/2012 ACT	2,250 MW COAL FIRED POWER PLANT	PULVERIZED COAL FIRED BOILER	COAL	7725	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNER (LNB), SEPARATED OVERFIRE AIR (SOFA) SYSTEM,	0.24	LB/MMBTU	30-DAY ROLLING AVG	BACT-PSD			
CA-1206	STOCKTON COGEN COMPANY	APMC STOCKTON COGEN	CA	SJ 85-04	221112	09/16/2011 ACT	49.9 MW COGENERATION POWER PLANT OWNED BY AIR PRODUCTS MANUFACTURING CORPORATION (APMC) STOCKTON COGEN AND LOCATED IN STOCKTON, CALIFORNIA	CIRCULATING FLUIDIZED BED BOILER	COAL	730	MMBTU/H	Nitrogen Oxides (NOx)	LOW BED TEMPERATUR STAGED COMBUSTION; SELECTIVE NON-CATALYTIC REDUCTION (SNCR)	50	PPM	@3% O2, 3-HR AVG	BACT-PSD	42	LB/H	3-HR AVG
MI-0399	DETROIT EDISON--MONROE	DETROIT EDISON	MI	93-09A	221112	12/21/2010 ACT	Utility--Coal fired power plant	Boiler Units 1, 2, 3 and 4	Coal	7624	MMBTU/H	Nitrogen Oxides (NOx)	Staged combustion, low-NOx burners, overfire air, and SCR.	0.08	LB/MMBTU	EACH, 12-MONTH ROLLING AVG.	BACT-PSD	222.6	T/MO	EACH, 12-MONTH ROLLING AVG.
MI-0400	WOLVERINE POWER	WOLVERINE POWER SUPPLY COOPERATIVE, INC.	MI	317-07	221112	06/29/2011 ACT	Coal-fired power plant.	2 Circulating Fluidized Bed Boilers (CFB1 & CFB2)	Petcoke/coal	3030	MMBTU/H EACH	Nitrogen Oxides (NOx)	SNCR (Selective Non-Catalytic Reduction)	1	LB/MW-H	GROSS OUTPUT; EACH; 30 D ROLL. AVG; NSPS	BACT-PSD	281.1	LB/H	EACH; 24H ROLL.AVG.; BACT
MI-0400	WOLVERINE POWER	WOLVERINE POWER SUPPLY COOPERATIVE, INC.	MI	317-07	221112	06/29/2011 ACT	Coal-fired power plant.	2 Circulating Fluidized Bed Boilers (CFB1 & CFB2) - EXCLUDING Startup & Shutdown	Petcoke/coal	3030	MMBTU/H each	Nitrogen Oxides (NOx)	SNCR (Selective Non-Catalytic Reduction)	0.07	LB/MMBTU	EACH, 30 D ROLLING AVG; BACT	BACT-PSD			
ND-0026	M.R. YOUNG STATION	MINNKOTA POWER COOPERATIVE	ND	PTC12003	221112	03/08/2012 ACT	Two lignite fired cyclone boilers.	Cyclone Boilers, Unit 1	Lignite	3200	MMBTU/H	Nitrogen Oxides (NOx)	SNCR plus separated over fire air	0.36	LB/MMBTU	30 DAY ROLLING AVERAGE	BACT-PSD	2070.2	LB/H	24 HOUR AV DURING STARTUP
ND-0026	M.R. YOUNG STATION	MINNKOTA POWER COOPERATIVE	ND	PTC12003	221112	03/08/2012 ACT	Two lignite fired cyclone boilers.	Cyclone Boilers, Unit 2	Lignite	6300	MMBTU/H	Nitrogen Oxides (NOx)	SNCR plus separated over fire air	0.35	LB/MMBTU	30 DAY ROLLING AVERAGE	BACT-PSD	3995.6	LB/H	24 HOUR AV DURING STARTUP
OK-0151	SOONER GENERATING STATION	O G AND E	OK	2010-338-C(M-1)PSD	221112	01/17/2013 ACT	The facility is an electricity generation plant (SIC Code 4911) located in an attainment area. The facility is currently operating under Permit No. 2010-338-TVR2 issued November 21, 2011.	COAL-FIRED BOILERS	COAL	550	MW	Nitrogen Oxides (NOx)	LOW-NOx BURNERS AND OVERFIRE AIR.	0.15	LB/MMBTU	30-DAY AVG	BART			
OK-0152	MUSKOGEE GENERATING STATION	O G AND E	OK	2005-271-C(M-5)PSD	221112	01/30/2013 ACT	The Muskogee Generating Station utilizes sub-bituminous coal, natural gas, and some waste products (used oil-sorb, used antifreeze, used solvents, used oil, chemical cleaning wastes, hazardous waste fuel, activated carbon, demineralizer resin, and waste water treatment sludge) to produce electricity (SIC 4911). The facility includes 3 large boiler units and auxiliary facilities for storage and processing of solid and liquid fuels and for handling ash and other wastes.	COAL-FIRED BOILER	COAL	550	MW	Nitrogen Oxides (NOx)	LOW-NOx BURNERS AND OVERFIRE AIR	0.15	LB/MMBTU	30-DAY AVG	BART			
TX-0554	COLETO CREEK UNIT 2	COLETO CREEK	TX	PSDTX1118 AND 83778	221112	05/03/2010 ACT	Coal-fired boiler	Coal-fired Boiler Unit 2	PRB coal	6670	MMBTU/H	Nitrogen Oxides (NOx)	low-NOx burners with OFA, Selective Catalytic Reduction	0.06	LB/MMBTU	ROLLING 30 DAY AVG	BACT-PSD	0.05	LB/MMBTU	ROLLING 12 MONTH AVG
TX-0556	HARRINGTON STATION UNIT 1 BOILER	SOUTHWESTERN PUBLIC SERVICE COMPANY	TX	PSDTX631M1 AMD 1388	221112	01/15/2010 ACT	The Southwestern Public Service Company (Xcel), the operator of a 3,630 MMBtu/hr coal fired electrical generating facility, is seeking authorization to install modifications to the Unit 1 Boiler at the Harrington Station Boiler Unit 1 in conjunction with a federally-mandated NOx reduction project. These modifications to this pollution control project include a separated overfire air windbox system, low-NOx burner tips and additional yaw control to the burners. These modifications will allow control of sufficient control emissions such that actual NOX emissions are expected to be reduced by an estimated 514 tons per year. However, as a result of these modifications, collateral increases in actual CO emissions are projected to be approximately 4,862 tons per year. Since this increase in CO emissions is in excess of 100 tpy, this project triggers the requirements for a PSD major modification. This project is not expected to increase other NAAQS constituents.	Unit 1 Boiler	Coal	3630	MMBTU/H	Nitrogen Oxides (NOx)	Separated overfire air windbox system; low-NOx burner tips and additional ya control to the burners.	1452	LB/H		BACT-PSD			

Pollutant Name: NO$_X$

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2
TX-0557	LIMESTONE ELECTRIC GENERATING STATION	NRG TEXAS POWER LLC	TX	PSDTX371M4 AND 8576	221112	02/01/2010 ACT	NRG Texas Power LLC (NRG) operates two coal and petroleum coke-fired steam/electric units, otherwise known as Limestone Units 1 and 2, which were originally permitted to operate in September 1981. These units are Combustion Engineering tangentially-fired, controlled circulation radiant reheat, divided furnace boilers. In January 2000 and August 2001, these units were authorized to install and operate low-NOX combustion systems, including secondary air staging technology and low-NOX burner tips with separated over-fire air. The tilting tangential firing system consists of ten elevations of solid fuel firing equipment with two elevations of Close Coupled Overfire Air and one elevation of warm-up gas firing. The modification requested under this amendment is a tuning of the existing low-NOx firing systems to induce deeper state combustion for NOx reductions with no new construction. Although, the deeper stage combustion will reduce NOX emissions, it will also result in a significant collateral increase in CO emissions above the current actual CO emission rates with no increase in authorized emission rates.	LMS Units 1 and 2	Coal	9061	MMBtu/H	Nitrogen Oxides (NOx)	Tuning of existing low-NOx firing system to induce deeper state combustion.	0.25	LB/MMBTU	30-DAY	BACT-PSD			
*TX-0577	WHITE STALLION ENERGY CENTER	WHITE STALLION ENERGY CENTER, LLC	TX	86088, PAL26, HAP28, PSDTX1160	221112	12/16/2010 ACT	WSEC proposes to construct and operate new steam-electric utility generating facilities using four circulating fluidized bed (CFB) boilers, each with a design maximum heat input of 3,300 million British thermal units per hour (MMBtu/hr) and 300 MW net electric output. The gross electric output of the four steam electric generators is about 1,320 MW; the net electric output of the WSEC is about 1,200 MW. The proposed fuels are Illinois Basin coal and petroleum coke. Low-sulfur distillate fuel oil is proposed as the CFB startup fuel. Steam condensation is supported by four water-cooled cooling towers, each with a cooling water circulation design rate of 161,000 gallons per minute. Coal and petroleum coke fuels, and limestone for the CFB beds may be received by barge, rail, or truck, and will be transported via partially enclosed conveyors to large stockpiles for storage. These materials will be conveyed to a crusher building before being stored in silos next to the boilers. Activated carbon for mercury control, lime for sulfur dioxide (SO2) control, and sand for CFB bed stabilization will be delivered via railcar or truck and conveyed pneumatically to storage silos. The fly ash and boiler bottom ash solid wastes will be stored in silos near the boilers, loaded into trucks, and sent to an on-site landfill.	CFB BOILER	COAL & PET COKE	3300	MMBTU/H	Nitrogen Oxides (NOx)	CFB AND SNCR	0.07	LB NOX/MMBTU	30-DAY ROLLING	BACT-PSD	0.1	LB NOX/MMBTU	1-HR
TX-0585	TENASKA TRAILBLAZER ENERGY CENTER	TENASKA TRAILBLAZER PARTNERS LLC	TX	PSDTX1123 AND HAP13, 84167	221112	12/30/2010 ACT	Coal-fired electric generating facility	Coal-fired Boiler	Sub-bituminous coal	8307	MMBTU/H	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	0.05	LB/MMBTU	12-MONTH ROLLING	BACT-PSD	0.06	LB/MMBTU	30-DAY ROLLING

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ELECTRONIC CORRESPONDENCE ONLY

July 31, 2020

Mr. Hassan M. Bouchareb
Environmental Analysis and Outcomes Division
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, Minnesota 55155-4194
Hassan.Bouchareb@state.mn.us

Re: MPCA Request for Information – Regional Haze Rule, Reasonable Progress, Four Factor Analysis
Minnesota Power's Taconite Harbor Energy Center (Title V Operating Permit No. 06100004-009)

Dear Mr. Bouchareb,

On January 29, 2020, the Minnesota Pollution Control Agency (MPCA) issued Minnesota Power (MP) a Regional Haze Rule Request for Information (RFI) for MP's Taconite Harbor Energy Center (THEC). The RFI requested that MP submit by July 31, 2020 a "Four Factor Analysis" for the following THEC emission units:

- Boiler No. 1 (EQUI 64 / EU 001) for NO_X and SO_2
- Boiler No. 2 (EQUI 5 / EU 002) for NO_X and SO_2

This letter is and the attached report is MP's response to this request.

MP trusts this submittal fulfills the MPCA RFI and thanks the MPCA for its review. Please contact me at mweglarz@mnpower.com or 218-343-0927 if you have questions or require additional information.

Sincerely,

Melissa S. Weglarz

Melissa Weglarz
Environmental Audit & Policy Manager
Minnesota Power Environmental & Land Mgmt.

enclosure: Regional Haze Four-Factor Analysis for NO_X and SO_2 Emissions Control
cc: Barr Engineering: Beau Thurman, Erik Boleman

Regional Haze Four-Factor Analysis for NO_X and SO_2 Emissions Control

Boiler No. 1 (EQUI 64 / EU 001)
Boiler No. 2 (EQUI 5 / EU 002)

Prepared for
Minnesota Power Taconite Harbor Energy Center

July 31, 2020

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Regional Haze Four-Factor Analysis for NO_X and SO_2 Emissions Control

July 31, 2020

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Abbreviations

BART	best available retrofit technology
BWCA	Boundary Waters Canoe Area
CEDR	Consolidated Emissions Data Repository
CFB	circulating fluidized bed
EPA	U.S. Environmental Protection Agency
FGR	flue gas desulfurization
IMPROVE	Interagency Monitoring of Protected Visual Environments
Isle Royale	Isle Royale National Park
LADCO	Lake Michigan Air Directors Consortium
lb	pound
LNB	low-NO_X Burners
MISO	Midwest Independent System Operator
MP	Minnesota Power
MPCA	Minnesota Pollution Control Agency
MMBtu/hr	Million British Thermal Units (BTU)/hour
MW	megawatt
NO	nitric oxide
NO_X	nitrogen oxides
O&M	operating and maintenance
OFA	over-fire air
PUC	Public Utilities Commission
RBLC	RACT/BACT/LAER Clearinghouse
RFI	Request for Information letter from Hassan Bouchareb of MPCA to Melissa Weglarz of Minnesota Power dated January 29, 2020
RHR	Regional Haze Rule
ROTA-MIX	rotating over-fire air and SNCR
SCR	selective catalytic reduction
SNCR	selective non-catalytic reduction
SIP	State Implementation Plan
SO_2	sulfur dioxide
THEC	Taconite Harbor Energy Center
tpy	tons per year
Voyageurs	Voyageurs National Park

1 Executive Summary

In accordance with Minnesota Pollution Control Agency's (MPCA's) January 29, 2020 Request for Information (RFI) Letter[1], Minnesota Power's (MP's) Taconite Harbor Energy Center (THEC) evaluated potential emissions reduction measures for sulfur dioxide (SO_2) and nitrogen oxides (NO_X) for Boiler No. 1 (EQUI 64 / EU 001) and Boiler No. 2 (EQUI 5 / EU 002) as part of the preparation of the State Implementation Plan (SIP) for the Regional Haze Rule (RHR)[2]. The analysis considers potential emissions reduction measures by addressing the four statutory factors laid out in 40 CFR 51.308(f)(2)(i) and pursuant to the final U.S. Environmental Protection Agency (EPA) RHR SIP guidance[3] (2019 RH SIP Guidance):

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

This report presents the four-factor analysis for NO_X and SO_2 emissions controls for the boilers at THEC. The four-factor analysis conclusions are summarized in Table 1-1 and Table 1-2 for NO_X and SO_2, respectively.

The NO_X four-factor analysis evaluated the following NO_X emissions reduction measures:

- Low-NO_X burners (coal tip replacement)
- Enhancements to existing selective non-catalytic reduction (SNCR) system

In the Factor 1 – Cost of Compliance analysis, no additional controls were identified to be cost effective (refer to Section 5.2 for more information). Therefore, the facility's existing NO_X emission performance (refer to Section 3 for more information) is sufficient for the MPCA's regional haze reasonable progress goal.

The SO_2 four-factor analysis evaluated the following SO_2 emissions reduction measures:

- Enhancements to the existing lime injection system

In the Factor 1 – Cost of Compliance analysis, no additional controls were identified to be cost effective (refer to Section 6.2 for more information). Therefore, the facility's existing SO_2 emission performance

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[1] January 29, 2020 letter from Hassan Bouchareb of MPCA to Melissa Weglarz of Minnesota Power.

[2] The U.S. Environmental Protection Agency (EPA) also refers to this regulation as the Clean Air Visibility Rule. The regional haze program requirements are promulgated at 40 CFR 51.308. The SIP requirements for this implementation period are specified in §51.308(f).

[3] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003.

(refer to Section 3 for more information) is sufficient for the MPCA's regional haze reasonable progress goal.

Table 1-1 Summary of NO_X Four-Factor Analysis

List of Emission Reduction Technology	Factor 1 Cost of Compliance ($/ton)	Factor 2 Time Necessary for Compliance	Factor 3 Energy and Non Air Quality Environmental Impacts of Compliance	Factor 4 Remaining Useful Life of the Source	Factor 5 Visibility Improvements	Does this Analysis Support the Installation of this Emission Reduction Technology?
Low NO_X Burners (Coal Tip Replacement)	$19,010/ton NO_X controlled	2 to 3 years	None expected	Conservatively Excluded from Analysis	Not Evaluated	No
ROFA/SNCR System Enhancements	$9,530/ton NO_X controlled	2 to 3 years	Minimal concern related to construction activities and additional truck traffic for SNCR deliveries	Conservatively Excluded from Analysis	Not Evaluated	No

Table 1-2 Summary of SO_2 Four-factor Analysis

List of Emission Reduction Technology	Factor 1 Cost of Compliance ($/ton)	Factor 2 Time Necessary for Compliance	Factor 3 Energy and Non Air Quality Environmental Impacts of Compliance	Factor 4 Remaining Useful Life of the Source	Factor 5 Visibility Improvements	Does this Analysis Support the Installation of this Emission Reduction Technology?
Lime Injection System Enhancements	$18,780/ton SO_2 controlled	2 years	Minimal concern related to construction activities and potential increases in ash for disposal	Conservatively Excluded from Analysis	Not Evaluated	No

2 Introduction

This section discusses the pertinent regulatory background information, and a description of THEC's boilers.

2.1 Four-factor Analysis Regulatory Background

The RHR published on July 15, 2005 by the EPA, defines regional haze as "visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources." The RHR requires state regulatory agencies to submit a series of SIPs in ten-year increments to protect visibility in certain national parks and wilderness areas, known as mandatory Federal Class I areas. The initial SIPs were due on December 17, 2007 and included milestones for establishing reasonable progress towards the visibility improvement goals, with the ultimate goal to achieve natural background visibility by 2064. The initial SIP was informed by best available retrofit technology (BART) analyses that were completed on all subject-to-BART sources. The second RHR planning period requires development and submittal of updated SIPs by July 31, 2021.

On January 29, 2020, the MPCA sent an RFI to THEC. The RFI stated that data from the Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring sites at Boundary Waters Canoe Area (BWCA) and Voyageurs National Park (Voyageurs) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of SO_2 and NO_X. In addition, emissions from sources in Minnesota could potentially impact Class I areas in nearby states, namely Isle Royale National Park (Isle Royale) in Michigan. Although Michigan is responsible for evaluating haze in Isle Royale, Michigan must consult with surrounding states, including Minnesota, on potential cross-state haze pollution impacts. As part of the planning process for the SIP development, MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to evaluate regional emission reductions.

The RFI also stated that THEC was identified as a significant source of NO_X and SO_2 located close enough to the BWCA and Voyageurs to potentially cause or contribute to visibility impairment. Therefore, the MPCA requested that THEC submit a "four-factor analysis" by July 31, 2020 for the emission units identified in Table 2-1 to support development of the SIP.

Table 2-1 Identified Emission Units

Unit	Unit ID	Applicable Pollutants
Boiler No. 1	EQUI 64 / EU 001	NO_X, SO_2
Boiler No. 2	EQUI 5 / EU 002	NO_X, SO_2

The analysis considers potential emissions reduction measures by addressing the four statutory factors which are laid out in 40 CFR 51.308(f)(2)(i):

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

The RFI letter to THEC specified that the "… analysis should be prepared using the U.S. Environmental Protection Agency guidance" referring to the final 2019 RH SIP Guidance[4].

This report describes the background and required procedure for conducting a four-factor analysis for NO_X and SO_2 as applied to the review of potential emissions controls at THEC for the units identified in Table 2-1.

2.2 Facility Description

THEC is a coal-fired steam electric utility generating plant consisting of three identical tangentially-fired coal-burning units located at 8124 West Highway 61 in Schroeder, Cook County, Minnesota on the north shore of Lake Superior. Boilers No. 1 and No. 2 are permitted to burn bituminous and subbituminous coal, as well as distillate fuel oil, which is used primarily for startup. Boiler No. 3 was shut down June 1, 2015 and is no longer permitted to operate. Boilers No. 1 and No. 2 have been idled since 2016, but are permitted to operate (see Title V Operating Permit No. 03100001-009) and MP continues to maintain the facility such that it could begin operation at any time. Boilers No. 1 and No. 2 are both rated to a maximum heat input rate of 900 MMBtu/hr, with net generating capacities of 79 MW and 76 MW, respectively.

When in operation, the facility uses western subbituminous coal which is received by boat and stored in an outdoor storage pile. Ash is pneumatically conveyed to and collected in a storage bin, then wetted to reduce fugitive emissions and disposed of at a landfill. Natural gas is not available at the site. Non-contact cooling water used to supply the boiler steam condensers is drawn from Lake Superior. The facility also includes a taconite ore loading dock that is owned and operated by the co-permittee, Cliffs-Erie LLC.

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[4] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003.

3 Existing Controls and Baseline Emission Rates

This section describes the existing NO_X and SO_2 emissions controls, and the baseline emissions rates which were used to evaluate the cost effectiveness for the associated emission reduction technologies.

3.1 Existing Emission Controls

Boilers No. 1 and No. 2 are each equipped with identical emission controls. For NO_X control, the boilers are equipped with SNCR with urea injection and over fire air (OFA) (TREA 22, TREA 5). These controls achieve a combined NO_X control efficiency of about 62% and typical emission rate of approximately 0.125 lb NO_X/MMBtu[5]. The permitted limit for both boilers is 0.160 lb NO_X/MMBtu on a 30-day rolling average basis. For SO_2 control, the boilers are equipped with Hydrated Lime Injection (TREA 23, TREA 6), and Sodium Bicarbonate Injection (TREA 28, TREA 27). These controls achieve a SO_2 control efficiency of about 65% and typical emission rate of 0.28 lb SO_2/MMBtu[6]. The permitted limit for both boilers is 0.30 lb SO_2/MMBtu on a 30-day rolling average basis.

3.2 Baseline Emissions Performance

The four-factor analysis requires the establishment of a baseline scenario for evaluating a potential emission reduction technology. The 2019 RH SIP Guidance considers the projected 2028 emissions scenario as a "reasonable and convenient choice" for the baseline control scenario[7] (emphasis added):

> *"Typically, a state will not consider the total air pollution control costs being incurred by a source or the overall visibility conditions that would result after applying a control measure to a source but would rather consider the incremental* ***cost and the change in visibility associated with the measure relative to a baseline control scenario. The projected 2028 (or the current) scenario can be a reasonable and convenient choice for use as the baseline control scenario for measuring the incremental effects of potential reasonable progress control measures on emissions, costs, visibility, and other factors****. A state may choose a different emission control scenario as the analytical baseline scenario. Generally, the estimate of a source's 2028 emissions is based at least in part on information on the source's operation and emissions during a*

---

[5] The 62% NO_X control efficiency for TREA 22 and TREA 5 noted here is the control efficiency specified for the control equipment in form GI-05A included in the Title V Operating Permit renewal application for THEC submitted in 2016. The quoted 0.125 lb NO_X/MMBtu emission rate is the annual average emission rate observed at Boilers No. 1 and 2 in calendar years 2015 and 2016.

[6] The 65% SO_2 control efficiency for TREA 28 and TREA 27 noted here is the control efficiency specified for the control equipment in form GI-05A included in the Title V Operating Permit renewal application for THEC submitted in 2016. The quoted 0.28 lb SO_2/MMBtu emission rate is the annual average emission rate observed at Boilers No. 1 and 2 in calendar year 2016.

[7] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003, Page 29.

> *representative historical period.* ***However, there may be circumstances under which it is reasonable to project that 2028 operations will differ significantly from historical emissions****. Enforceable requirements are one reasonable basis for projecting a change in operating parameters and thus emissions; energy efficiency, renewable energy, or other such programs where there is a documented commitment to participate and a verifiable basis for quantifying any change in future emissions due to operational changes may be another. A state considering using assumptions about future operating parameters that are significantly different than historical operating parameters should consult with its EPA Regional office."*

THEC Boilers No. 1 and No. 2 have been idled since 2016. Despite their current idled status, THEC Boilers No. 1 and No. 2 are still permitted to operate, and as such MP has completed this four-factor analysis using conservative assumptions of future operation and remaining equipment life in the event that the units are restarted. MP has maintained a modest fuel supply onsite to allow the units to be restarted to provide reliability to the electric system or address system emergencies. MP has also offered THEC Boilers No. 1 and No. 2 into the Midwest Independent System Operator's (MISO's) capacity auction each year since the units were idled. THEC has not been selected into MISO's annual capacity auction to-date. MP continues to maintain the facility such that it could begin operation at any time, but there are currently no plans to restart the units.

For both the NO_X and SO_2 baseline emissions, MP conservatively assumed that the operation of THEC Boilers No. 1 and No. 2 prior to their idling in late 2016 would be representative of their operation in 2028. Table 3-1 and Table 3-2 below shows the annual fuel usage for calendar years 2011 through 2015 for THEC Boilers No. 1 and No. 2, respectively. This represents the five most recent full calendar years of operation for the boilers. The values presented in this table were sourced directly from the Annual Emission Inventory Reports submitted to the MPCA via the Consolidated Emissions Data Repository (CEDR) for the calendar years specified.

Table 3-1 THEC Boiler No. 1 (EQUI 64 / EU 001) Historical Fuel Usage

Parameter	2011	2012	2013	2014	2015
Coal Fired (short ton/year)	253,593	224,487	180,741	256,023	268,677
Fuel Oil Fired (1,000 gal/year)	30.9	31.5	55.2	19.5	34.6
Total Heat Input (MMBtu/year)	4,575,772	4,054,231	3,276,941	4,616,605	4,830,987

Table 3-2 THEC Boiler No. 2 (EQUI 5 / EU 002) Historical Fuel Usage

Parameter	2011	2012	2013	2014	2015
Coal Fired (short ton/year)	206,840	102,755	220,489	208,881	262,050
Fuel Oil Fired (1,000 gal/year)	48.7	37.2	39.1	51.1	23.6
Total Heat Input (MMBtu/year)	3,736,786	1,855,899	3,989,114	3,764,819	4,704,992

Based on these historic operating rates and emission rates, MP conservatively assumed that the highest total heat input observed for each boiler in this five year period, rounded up to the nearest 50,000 MMBtu would be representative of their 2028 operation. This is 4,850,000 MMBtu/year for Boiler No. 1 and 4,750,000 MMBtu/year for Boiler No. 2. To simplify the evaluations in this document, MP conservatively assumed that both boilers would operate at the higher of these two values, 4,850,000 MMBtu/year.

For the 2028 NO_X and SO_2 emission rates, the permitted limits for both Boilers No. 1 and 2 are 0.160 lb NO_X/MMBtu and 0.30 lb SO_2/MMBtu[8]. These limits only became effective relatively recently[9,10] and as such there is a limited record of operation of the boilers with the limits in place. MP operators and engineers observed a typical emission rate of at 0.125 lb NO_X/MMBtu[11] and 0.28 lb SO_2/MMBtu[12] for both Boilers

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[8] Both the NO_X and SO_2 limits apply to each boiler individually are on a 30-day rolling average basis and were established by Consent Decree (CASE 0:14-cv-02911-ADM-LIB Document 3-1).

[9] The 0.16 lb NO_X/MMBtu limit became effective on the “Date of Entry of the Consent Decree”, which is July 16, 2014, as noted within Consent Decree (CASE 0:14-cv-02911-ADM-LIB Document 3-1) Paragraph 84.

[10] The 0.30 lb SO2/MMBtu limit became effective on December 31, 2015 as noted within Consent Decree (CASE 0:14-cv-02911-ADM-LIB Document 3-1) Paragraphs 104 and 105.

[11] The quoted 0.125 lb NO_X/MMBtu emission rate is the annual average emission rate observed at Boilers No. 1 and 2 in calendar years 2015 and 2016, the calendar years of operation after the 0.16 lb NO_X/MMBtu limit became effective.

[12] The quoted 0.28 lb SO_2/MMBtu emission rate is the annual average emission rate observed at Boilers No. 1 and 2 in calendar year 2016, the calendar year of operation after the 0.30 lb SO_2/MMBtu limit became effective.

No. 1 and 2 after the limits became effective. These estimates were used for the 2028 projected emission rates.

Combining the 2028 projected total heat input with the expected emission rates from the boilers establishes the conservatively projected baseline emissions to be the values shown in Table 3-3 below.

Table 3-3 Baseline Emissions for THEC Boiler No. 1 (EQUI 64 / EU 001) and No. 2 (EQUI 5 / EU 002)

Emission Unit	NO_X (ton/year)	SO_2 (ton/year)
Boiler No. 1 (EQUI 64 / EU 001)	303[1]	679[2]
Boiler No. 2 (EQUI 5 / EU 002)	303[1]	679[2]

[1] $303\,\frac{ton\ NO_X}{year} = 4{,}850{,}000\,\frac{MMBtu}{yr} \times 0.125\,\frac{lb\ NO_X}{MMBtu} \times \frac{ton}{2{,}000\ lb}$

[2] $679\,\frac{ton\ NO_X}{year} = 4{,}850{,}000\,\frac{MMBtu}{yr} \times 0.280\,\frac{lb\ SO_2}{MMBtu} \times \frac{ton}{2{,}000\ lb}$

4 Four-factor Analysis Overview

This section summarizes the four-factor analysis approach with respect to the Regional Haze program detailed in the 2019 RH SIP guidance.

4.1 Emission Control Options

EPA states that the "first step in characterizing control measures for a source is the identification of technically feasible control measures" but recognized that "there is no statutory or regulatory requirement to consider all technically feasible measures or any particular measures."[13] However, a "state must reasonably pick and justify the measures that is will consider."[14] The EPA provides the following examples of the types of emission control measures states may consider[15]:

- Emission reductions through improved work practices
- Retrofits for sources with no existing controls
- Upgrades or replacements for existing, less effective controls
- Year-round operation of existing controls
- Fuel mix with inherently lower SO_2, NO_X, and/or PM[16] emissions. States may also determine that it is unreasonable to consider some fuel-use changes because they would be too fundamental to the operation and design of a source.
- Operating restrictions on hours, fuel input, or product output to reduce emissions.
- Energy efficiency and renewable energy measures that could be applied elsewhere in a state to reduce emissions from EGUs.
- Basic smoke management practices and smoke management programs for agricultural or wildland prescribed fires.

Not all of these potential control measures are applicable to THEC. MP focused this evaluation on potential upgrades to or replacement of the existing control equipment. The following methodology was used to select a reasonable set of emission control technologies that were considered in the four-factor analysis:

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[13] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003, page 28-29.

[14] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003, page 29.

[15] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003, page 29-30.

[16] Please note that PM emissions were not included in the RFI as potentially impacting visibility and thus are not included in this evaluation.

1. Search the RBLC[17] for available control technologies with the following search criteria:
    - Similar emission unit type (utility boilers larger than 250 MMBtu/hr)
    - Similar fuel (coal)
    - 10-year look back
2. Eliminate technologies that would not would not apply to the specific emission unit under consideration
3. Advance the remaining technologies for consideration in the four-factor analysis

MP also considered a fuel-mix change to utilize natural gas instead of or in addition to coal combustion.

4.1.1 NO_X Control Options

The RBLC search for coal-fired utility boilers for NO_X is presented in Appendix A.1. Most RBLC entries specify that multiple control technologies have been implemented at each facility. To avoid confusion, MP has summarized the individual control technologies noted in the RBLC into Table 4-1 below along with example RBLC IDs where the technology was implemented and the applicability to THEC. MP has also included one potential control option (fuel conversion to natural gas) that was not specified in the RBLC, but is another control measures that can be considered as noted in section 4.1.

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[17] RACT/BACT/LAER Clearinghouse (RBLC) as maintained by USEPA (link to RBLC website)

Table 4-1 Coal-Fired Utility Boilers RBLC Summary – NO_X

Technology	Example RBLC IDs	Applicable to THEC?
Low-NO_X Burners (LNB)	AZ-0055 OK-0151 TX-0554	Yes
Over-Fire Air Includes Separated Over-Fire Air (SOFA) and Rotating Over-Fire Air (ROFA)	AZ-0055 OK-0151 TX-0554	Yes[1]
Selective Non-Catalytic Reduction (SNCR)	CA-1206 MI-0400 TX-0577	Yes[1]
Selective Catalytic Reduction (SCR)	MI-0399 TX-0554 TX-0585	No[2]
Low Bed Temperatures	CA-1206	No[3]
Convert Boilers to Use Natural Gas as Fuel	N/A[4]	No[5]

Table Footnotes

[1] THEC Boilers No. 1 and No. 2 are both equipped with SNCR and ROFA (TREA 22 and TREA 5, respectively). Installation of other types of over-fire air systems would interfere with the existing ROFA systems and require significant alterations to the boiler, and thus are impractical to evaluate.

[2] SCR is considered not applicable primarily due to space limitations at THEC. Additionally, the relatively small size of the boilers and ductwork are likely to make achieving the required flue gas temperatures for SCR to work properly a challenge.

[3] Low bed temperatures are a control technology for circulating fluidized bed (CFB) boilers. THEC Boilers No. 1 and No. 2 are both tangentially-fired boilers.

[4] There are no RBLC entries which specify a fuel switch to natural gas as a control technology. However, it is included as changes to a facility's fuel mix are included in the types of potential control options under consideration for regional haze. See Section 4.1 for details.

[5] There is currently no access to natural gas at THEC. The nearest natural gas pipeline terminates in Silver Bay, MN.

Based on this information, the reasonable set of control technologies considered in this four-factor analysis are:

- Low-NO_X Burners (LNB, achieved via coal tip replacement)
- Enhancements to the existing ROFA and SNCR systems

4.1.2 SO2 Control Options

The RBLC search for coal-fired utility boilers for SO_2 is presented in Appendix A.2. Most RBLC entries specify that multiple control technologies have been implemented at each facility. To avoid confusion, MP has summarized the individual control technologies noted in the RBLC into Table 4-2 below along with example RBLC IDs where the technology was implemented and the technology's applicability to THEC. MP has also included one potential control option (fuel conversion to natural gas) that was not specified in the RBLC, but is another control measures that can be considered as noted in section 4.1.

Table 4-2 Coal-Fired Utility Boilers RBLC Summary – SO_2

Technology	Example RBLC IDs	Applicable to THEC?
Reagent (Lime, Limestone, Sodium Bicarbonate) Injection	CA-1206 KY-0100	Yes[1]
Spray Dryer	MI-0400 TX-0554	No[2]
Wet Lime Scrubbing (Wet Flue-Gas Desulfurization, FGD)	MI-0399 TX-0585	No[3]
Convert Boilers to Use Natural Gas as Fuel	N/A[4]	No[5]

Table Footnotes

[1] THEC Boilers No. 1 and No. 2 are both equipped with Hydrated Lime Injection (TREA 23 and TREA 6, respectively) and Sodium Bicarbonate Injection (TREA 28 and TREA 27, respectively).

[2] Space limitations at THEC make the installation of a spray dryer, storage of wastes generated by spray dryer, and waste loading materials, infeasible.

[3] The Coal Combustion Residuals (CCR) Rule (40 CFR 257 Subpart D) requires dewatering of wet FGD slurry before disposal, or significant design, operation, and closure requirements for drying ponds. Space limitations at THEC make the installation of a scrubber, and dewatering equipment or drying ponds infeasible.

[4] There are no RBLC entries which specify a fuel switch to natural gas as a control technology. However, it is included for completeness as changes to a facility's fuel mix are included in the types of potential control options under consideration for regional haze. See Section 4.1 for details.

[5] There is currently no access to natural gas at THEC. The nearest natural gas pipeline terminates in Silver Bay, MN.

Based on this information, Reagent Injection is the only applicable control option for THEC. Since the facility already operates Hydrated Lime Injection and Sodium Bicarbonate Injection systems, enhancement of the existing injection systems is the only applicable control technology considered in this four-factor analysis.

4.2 Factor 1 – Cost of Compliance

Factor #1 considers and estimates, as needed, the capital and annual operating and maintenance (O&M) costs of the control measure. As directed by the 2019 RH SIP Guidance at page 21, costs of emissions controls follow the accounting principles and generic factors from the EPA Air Pollution Control Cost Manual (EPA Control Cost Manual) [18] unless more refined site-specific estimate are available. Under this

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[18] US EPA, "EPA Air Pollution Control Cost Manual, Sixth Edition," January 2002, EPA/452/B-02-001. The EPA has updated certain sections and chapters of the manual since January 2002. These individual sections and chapters may be accessed at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution as of the date of this report.

step, the annualized cost of installation and operation on a dollars per ton of pollutant removed ($/ton) of the control measure, referred to as "average cost effectiveness."

Generally, if the average cost effectiveness is greater than a threshold, the cost is considered to not be reasonable, pending an evaluation of other factors. Conversely, if the average cost effectiveness is less than a threshold, then the cost is considered reasonable for purposes of Factor #1, pending an evaluation of whether the absolute cost of control (i.e., costs in absolute dollars, not normalized to $/ton) is unreasonable. This situation is particularly applicable to a source with existing emissions controls with an intermediate or high degree of effectiveness, as is the case for the THEC Boilers No. 1 and No. 2 due to their existing NO_X and SO_2 emissions controls.

The cost of an emissions control measure is derived using capital and annual O&M costs. Capital costs generally refer to the money required to design and build the system. This includes direct costs, such as equipment purchases, and installation costs. Indirect costs, such as engineering and construction field expenses and lost revenue due to additional unit downtime in order to install the additional control measure(s), are considered as part of the capital calculation. Annual O&M costs include labor, supplies, utilities, etc., as used to determine the annualized cost in the numerator of the cost effectiveness value. The denominator of the cost effectiveness value (tons of pollutant removed) is derived as the difference in: 1) projected emissions using the current emissions control measures (baseline emissions), as described in Section 3.2, in tons per year (tpy), and 2) expected annual emissions performance through installation of the additional control measure (controlled emissions), also in tpy.

For purposes of calculating cost effectiveness, THEC compared the estimated annual emission reductions for each control measure relative to the baseline emissions as presented in Table 3-3.

4.3 Factor 2 – Time Necessary for Compliance

Factor #2 is considered by MPCA in setting reasonable deadlines for the selected control. This includes the planning, installation, and commissioning of the selected control, as well as environmental permitting and associated review.

4.4 Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance

Factor #3 involves consideration of the energy and non-air environmental impacts of each control measure. Non-air quality impacts may include solid or hazardous waste generation, wastewater discharges from a control device, increased water consumption, and land use. The environmental impact analysis is conducted based on consideration of site-specific circumstances.

The energy impact analysis considers whether use of an emissions control technology results in any significant or unusual energy penalties or benefits. Energy use may be evaluated on an energy used per unit of production basis; energy used per ton of pollutant controlled or total annual energy use.

4.5 Factor 4 – Remaining Useful Life of the Source

Factor #4 is the remaining useful life of the source, which is the difference between the date that additional emissions controls will be put in place and the date that the facility permanently ceases operation. Generally, the remaining useful life of the "source" (meaning, the emission unit) is assumed to be longer than the useful life of the emissions control measure unless there is an enforceable cease-operation requirement. In the presence of an enforceable end date, the cost calculation can use a shorter period to amortize the capital cost.

For the purpose of this evaluation, the remaining useful life for Boilers No. 1 and No. 2 are conservatively assumed to be longer than the useful life of the additional emission controls measures. Therefore, the expected useful life of the *control measure itself, not the emission unit,* is used to calculate the emissions reductions, amortized costs, and the resulting cost per ton removed.

5 NO_X Four-factor Analysis

This section identifies and describes various NO_X emission reduction technologies, evaluates the four statutory factors for THEC Boilers No. 1 and No. 2, and proposes a NO_X emission limit for the selected emission reduction technology. Consistent with EPA's guidance and MPCA direction, THEC has completed a four-factor analysis for NO_X as summarized in Sections 5.1 to 5.5.

5.1 NO_X Control Measures Overview

There are three mechanisms by which NO_X production occurs in boilers. They are fuel, thermal, and prompt NO_X formation.

Fuel bound NO_X is primarily a concern with solid and liquid fuel combustion sources; it is formed as nitrogen compounds in the fuel are oxidized in the combustion process. Bituminous and subbituminous coal, the type combusted in THEC Boilers No. 1 and No. 2, naturally contains 0.5 to 2 weight percent nitrogen and can account for up to 80 percent of the total NO_X emissions from coal combustion[19].

NO_X is also generated in the combustion process through thermal NO_X formation. This mechanism arises from the thermal dissociation of nitrogen and oxygen molecules in combustion air to nitric oxide (NO). The thermal oxidation reaction is as follows:

$$N_2 + O_2 \rightarrow 2NO \qquad (1)$$

Downstream of the flame, significant amounts of NO_2 can be formed when NO is mixed with air. The reaction is as follows:

$$2NO + O_2 \rightarrow 2NO_2 \qquad (2)$$

Thermal NO_X formation is a function of the residence time, free oxygen, and peak reaction temperature.

Prompt NO_X is a form of thermal NO_X which is generated at the flame boundary. It is the result of reactions between nitrogen and hydrocarbon radicals generated during combustion. Only a small fraction of NO_X emissions from combustion sources are from prompt NO_X formation.

Theoretically, several techniques can be used to reduce NO_X emissions from tangentially-fired coal-fueled utility boilers, as listed in Table 4-1. Table 5-1 lists the control technologies identified as the applicable set of control technologies in Section 4.1.1 and are further evaluated in this section.

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[19] Section 1.1.3.3 of AP-42, Fifth Edition, Chapter 1.1 - *Bituminous and Subbituminous Coal Combustion*, September 1998.

Table 5-1 Additional NO_X Control Measures with Potential Application to THEC Boilers No. 1 and 2

Control Technology
Low-NO_X Burners (LNB, achieved via coal tip replacement)
Enhancements to the existing ROFA and SNCR systems

MP estimates that replacement of the coal tip (LNB) would result in a typical emission rate of 0.12 lb NO_X/MMBtu, and that the enhancements to the existing SNCR and ROFA systems would result in a typical emission rate of 0.11 to 0.12 lb NO_X/MMBtu. For the purposes of this evaluation, MP has conservatively assumed that these enhancements would achieve the lower estimate of 0.11 lb NO_X/MMBtu. Combining these emission rates with the projected 2028 operating rates and baseline emission rates determined in Section 3.2 of this document results in the projected emissions reduction estimates for each boiler shown in Table 5-2.

Table 5-2 Potential NO_X Emission Reductions for THEC Boiler No. 1 (EQUI 64 / EU 001) and No. 2 (EQUI 5 / EU 002)

Emission Unit	Baseline NO_X (ton/year)[1]	NO_X Emissions with LNB (ton/year)	Emissions Reduction from LNB (ton/year)	NO_X Emissions with SNCR/ROFA Enhancements (ton/year)	Emissions Reduction from SNCR/ ROFA Enhancements (ton/year)
Boiler No. 1 (EQUI 64 / EU 001)	303	291[2]	12[3]	267[4]	36[3]
Boiler No. 2 (EQUI 5 / EU 002)	303	291[2]	12[3]	267[4]	36[3]

[1] See Table 3-3

[2] $291 \frac{ton\ NO_X}{year} = 4{,}850{,}000 \frac{MMBtu}{yr} \times 0.120 \frac{lb\ NO_X}{MMBtu} \times \frac{ton}{2{,}000\ lb}$

[3] Difference between baseline emissions and emissions estimate with control equipment added.

[4] $267 \frac{ton\ NO_X}{year} = 4{,}850{,}000 \frac{MMBtu}{yr} \times 0.110 \frac{lb\ NO_X}{MMBtu} \times \frac{ton}{2{,}000\ lb}$

5.2 Factor 1 – Cost of Compliance

MP has completed a screening-level cost estimate for the selected NO_X emission control measures for each boiler. As noted in section 4.2, these control cost estimates were developed in accordance with the EPA Control Cost Manual. The capital cost estimates are considered by MP's engineering staff to be conservatively low, based on their considerable experience with projects at THEC and informal conversations with other companies that have completed similar types of projects at other facilities. A more detailed cost estimate is likely to increase the estimated costs for installing and implementing either of these technologies. Cost summary spreadsheets for the NO_X emission control measures are provided in Appendix B.

The cost effectiveness analysis compares the annualized cost of the technology per ton of pollutant removed and is evaluated on 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, a 20-year life (before new and extensive capital is needed to maintain and repair the equipment) is used for the SNCR and ROFA enhancements, and a 10-year life is used for the coal tip replacement (LNB). A 3.25% interest is assumed in annualizing capital costs[20].

The resulting cost effectiveness calculations are summarized in Table 5-3. Please note that THEC Boilers No. 1 and No. 2 have identical estimated emission reductions and costs estimated for each control technology in Table 5-2. As such, the values presented in Table 5-3 are representative of both boilers.

Table 5-3 NO_X Control Cost Summary, per Unit Basis

Additional Emissions Control Measure	Installed Capital Cost ($)	Annualized Capital Cost ($/yr)	Annual Operating Costs ($/yr)	Total Annualized Costs ($/yr)	Annual Emissions Reduction (tpy)	Pollution Control Cost Effectiveness ($/ton)
Low-NO_X Burners (LNB, Coal Tip Replacement)	$609,375	$72,352	$155,775	$228,127	12	$19,010
Enhancements to the existing ROFA and SNCR systems	$1,218,750	$83,824	$259,221	$343,045	36	$9,530

MP has determined that neither of these control technologies are cost effective based on a consideration of RHR analyses conducted in other states. Sections 5.3 through 5.5 provide a screening-level summary of the remaining three factors evaluated for the NO_X emission control measures, understanding that these projects represent substantial capital investments that are not justified on a cost per ton or absolute cost basis.

5.3 Factor 2 – Time Necessary for Compliance

Factor #2 estimates the amount of time needed for full implementation of the different control measures. Typically, time for compliance includes the time needed to develop and approve the new emissions limit into the SIP by state and federal action, then to implement the project necessary to meet the SIP limit via installation and tie-in of equipment for the emissions control measure.

The technologies would require significant resources and time of at least two to three years to engineer, permit, and install the equipment. Currently both THEC Boilers No. 1 and No. 2 are idled. It is unknown at this time if these units will be restarted, retrofitted, refueled, or retired. Any substantial investments in THEC Boilers No. 1 and No. 2 would likely require approval from the Public Utilities Commission (PUC) and, if the unit is retrofitted or refueled, would require MPCA permitting.

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[20] Bank Prime Rate for July 16, 2020 from https://www.federalreserve.gov/releases/h15/.

5.4 Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance

As stated previously, THEC Boilers No. 1 and No. 2 were idled in 2016 and have not operated since then. MP has maintained a modest fuel supply onsite to allow the units to be restarted to provide reliability to the electric system or address system emergencies. MP has also offered THEC Boilers No. 1 and No. 2 into MISO's capacity auction each year since the units were idled. THEC has not been selected into MISO's annual capacity auction to-date. MP currently plans to continue maintaining the facility such that it could begin operation at any time, but there are currently no plans to restart the units. Any substantial investments in THEC Boilers No. 1 and No. 2 would likely require approval from the Public Utilities Commission (PUC) and, if the unit is retrofitted or refueled, would require MPCA permitting.

Replacing the coal tip (LNB) represents a fairly simple change to the design of the existing burners and does not present any anticipated energy or non-air quality environmental impacts.

Enhancing the existing ROFA and SNCR systems will result in an increase in construction activities that could increase water run-off into Lake Superior. However, this would only be during the construction phase of the project, the construction activities would be permitted, and the appropriate mitigation techniques would be implemented as-needed. The increase in SNCR reagent usage will also require a small increase in truck traffic from deliveries, thus increasing fugitive particulate matter emissions.

5.5 Factor 4 – Remaining Useful Life of the Source

MP's August 22, 2019 *Remaining Life Depreciation Petition*[21] states that the THEC Boilers No. 1 and No. 2 end of useful life is December 31, 2026. This date is primarily used for ratemaking purposes and should not be construed as a retirement commitment date for the boilers. For maximum conservatism in this analysis, the useful life of the individual control measures, not the emission units, is used to calculate emission reductions, amortized costs and cost effectiveness on a dollar per ton basis.

5.6 Proposed NO_X Controls and Emissions Rates

This analysis does not support the installation of additional NO_X emissions measures at THEC Boilers No. 1 and No. 2 beyond those described in Section 3.1. The available and potential technically feasible control strategies for the boilers are considered economically infeasible.

As such, MP proposes to retain the existing NO_X emission limits and control technologies at THEC.

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[21] Docket No. E015/D-19-534, Document 20198-155376-01.

6 SO_2 Four-factor Analysis

This section identifies and describes various SO_2 emission reduction technologies, evaluates the four statutory factors for THEC Boilers No. 1 and No. 2, and proposes a SO_2 emission limit for the selected emission reduction technology. Consistent with EPA's guidance and MPCA direction, MP has completed a four-factor analysis for SO_2 as summarized in Sections 6.1 to 6.5.

6.1 SO_2 Control Measures Overview

SO_2 emissions occur as a result of oxidation of sulfur in the fuels combusted. Theoretically, several techniques can be used to reduce SO_2 emissions from tangentially-fired coal-fueled utility boilers, as listed in Table 4-2. Table 6-1 lists the control technologies identified as the reasonable set of control technologies in Section 4.1.2 and are further evaluated in this section.

Table 6-1 Additional SO_2 Control Measures with Potential Application to THEC Boilers No. 1 and 2

Control Technology
Enhancements to the existing Lime Injection System

Based on operating experience at THEC and other MP facilities and restrictions caused by the boilers' designs, MP estimates that the enhancements to the existing lime injection systems would result in a marginal improvement in performance, achieving a typical emission rate of 0.25 lb SO_2/MMBtu. Combining this emission rate with the projected 2028 operating rates and baseline emission rates determined in Section 3.2 of this document results in the projected emissions reduction estimates for each boiler shown in Table 6-2.

Table 6-2 Potential SO_2 Emission Reductions for THEC Boiler No. 1 (EQUI 64 / EU 001) and No. 2 (EQUI 5 / EU 002)

Emission Unit	Baseline NO_X (ton/year)[1]	SO_2 Emissions with Lime Injection System Enhancements (ton/year)
Boiler No. 1 (EQUI 64 / EU 001)	679	606[2]
Boiler No. 2 (EQUI 5 / EU 002)	665	606[2]

[1] See Table 3-3

[2] $606\,\frac{ton\ NO_X}{year} = 4{,}850{,}000\,\frac{MMBtu}{yr} \times 0.250\,\frac{lb\ NO_X}{MMBtu} \times \frac{ton}{2{,}000\ lb}$

[3] Difference between baseline emissions and emissions estimate with control equipment added.

6.2 Factor 1 – Cost of Compliance

MP has completed a screening-level cost estimate for the selected SO_2 emission control measure. As noted in section 4.2, these control cost estimates were developed in accordance with the EPA Control Cost

Manual. The capital cost estimates are considered by THEC's plant engineering staff to be conservatively low, based on their considerable experience with projects at THEC and their informal conversations with other companies that have completed similar types of projects at other facilities. A more detailed cost estimate is likely to increase the costs for installing and implementing this technology. Cost summary spreadsheets for the SO_2 emission control measures are provided in Appendix C.

The cost effectiveness analysis compares the annualized cost of the technology per ton of pollutant removed and is evaluated on 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, a 20-year life (before new and extensive capital is needed to maintain and repair the equipment) at 3.25% interest is assumed in annualizing capital costs[22].

The resulting cost effectiveness calculation is summarized in Table 6-3. Please note that THEC Boilers No. 1 and No. 2 are identical, and have identical estimated emission reductions and costs estimated for each control technology in Table 6-2. As such, the values presented in Table 6-3 are representative of both boilers.

Table 6-3 SO_2 Control Cost Summary, per Unit Basis

Additional Emissions Control Measure	Installed Capital Cost ($)	Annualized Capital Cost ($/yr)	Annual Operating Costs ($/yr)	Total Annualized Costs ($/yr)	Annual Emissions Reduction (tpy)	Pollution Control Cost Effectiveness ($/ton)
Enhancements to the existing Lime Injection System	$3,656,250	$251,473	$1,119,705	$1,371,178	73	$18,780

MP has determined that this control technology is not cost effective based on a consideration of RHR analyses conducted in other states. Sections 6.3 through 6.5 provide a screening-level summary of the remaining three factors evaluated for the SO_2 emission control measures, understanding that these projects represent substantial capital investments that are not justified on a cost per ton or absolute cost basis.

6.3 Factor 2 – Time Necessary for Compliance

Factor #2 estimates the amount of time needed for full implementation of the different control measures. Typically, time for compliance includes the time needed to develop and approve the new emissions limit into the SIP by state and federal action, then to implement the project necessary to meet the SIP limit via installation and tie-in of equipment for the emissions control measure.

Based on previous project experience and technical judgement, MP expects the lime injection enhancement project would require significant resources and time of approximately two years to obtain

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[22] Bank Prime Rate for July 16, 2020 from https://www.federalreserve.gov/releases/h15/.

project regulatory approvals, engineer, and install the equipment. Currently both THEC Boilers No. 1 and No. 2 are idled. It is unknown at this time if these units will be restarted, retrofitted, refueled, or retired. Any substantial investments in THEC Boilers No. 1 and No. 2 would likely require approval from the Public Utilities Commission (PUC) and, if the unit is retrofitted or refueled, would require MPCA permitting.

6.4 Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance

As stated previously, THEC Boilers No. 1 and No. 2 were idled in 2016 and have not operated since then. MP has maintained a modest fuel supply onsite to allow the units to be restarted to provide reliability to the electric system or address system emergencies. MP has also offered THEC Boilers No. 1 and No. 2 into MISO's capacity auction each year since the units were idled. THEC has not been selected into MISO's annual capacity auction to-date. MP currently plans to continue maintaining the facility such that it could begin operation at any time, but there are currently no plans to restart the units. Any changes to the operating status of THEC Boilers No. 1 and No. 2 would require approval from the Public Utilities Commission (PUC) and, if the unit is retrofitted or refueled, permitted the MPCA.

Enhancing the existing lime injection systems will result in an increase in construction activities that could increase water run-off into Lake Superior. However, this would only be during the construction phase of the project, the construction activities would be permitted, and the appropriate mitigation techniques would be implemented as-needed. The increased lime injection will result in more particulate matter in the flue gas. While the boilers will still be required to use their existing particulate matter control equipment and meet their respective particulate matter emission limits, this will result in an increase in ash collected by the control equipment which will need to be disposed.

6.5 Factor 4 – Remaining Useful Life of the Source

MP's August 22, 2019 *Remaining Life Depreciation Petition*[23] states that the THEC Boilers No. 1 and No. 2 end of useful life is December 31, 2026. This date is primarily used for ratemaking purposes and should not be construed as a retirement commitment date for the boilers. For maximum conservatism in this analysis, the useful life of the individual control measure, not the emission units, is used to calculate emission reductions, amortized costs and cost effectiveness on a dollar per ton basis.

6.6 Proposed SO_2 Controls and Emissions Rates

This analysis does not support the installation of additional SO_2 emissions measures at the THEC Boilers No. 1 and No. 2 beyond those described in Section 3.1. The available and potential technically feasible control strategies for the boilers are considered economically.

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[23] Docket No. E015/D-19-534, Document 20198-155376-01.

As such, MP proposes to retain the existing SO_2 emission limits and control technologies at THEC.

7 Conclusion

MP's THEC evaluated potential emissions reduction measures for NO_X and SO_2 for Boiler No. 1 (EQUI 64 / EU 001) and Boiler No. 2 (EQUI 5 / EU 002) in response to an RFI from the MPCA. No additional NO_X or SO_2 controls were identified to be cost effective (refer to Sections 5.2 and 6.2 for more information). Therefore, the facility's existing NO_X and SO_2 emission performance (refer to Section 3 for more information) is sufficient for the MPCA's regional haze reasonable progress goal.

Appendix A

RACT/BACT/LAER Clearinghouse (RBLC) Review Summaries

Appendix A.1

RBLC Search for Coal-Fired Utility Boilers for NO_X

Minnesota Power - Taconite Harbor Energy Center
Regional Haze RFI
Appendix A-1: RBLC Search for Coal-Fired Utility Boilers for NO_X

Pollutant Name: NO_X

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
AZ-0055	NAVAJO GENERATING STATION	SALT RIVER PROJECT AGRICULTURAL AND POWER DISTRICT	AZ	AZ 08-01	221112	02/06/2012 ACT	2,250 MW COAL FIRED POWER PLANT	PULVERIZED COAL FIRED BOILER	COAL	7725	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNER (LNB), SEPARATED OVERFIRE AIR (SOFA) SYSTEM,	0.24	LB/MMBTU	30-DAY ROLLING AVG	BACT-PSD	0			0		
AZ-0055	NAVAJO GENERATING STATION	SALT RIVER PROJECT AGRICULTURAL AND POWER DISTRICT	AZ	AZ 08-01	221112	02/06/2012 ACT	2,250 MW COAL FIRED POWER PLANT	PULVERIZED COAL FIRED BOILER	COAL	7725	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNER (LNB), SEPARATED OVERFIRE AIR (SOFA) SYSTEM,	0.24	LB/MMBTU	30-DAY ROLLING AVG	BACT-PSD	0			0		
AZ-0055	NAVAJO GENERATING STATION	SALT RIVER PROJECT AGRICULTURAL AND POWER DISTRICT	AZ	AZ 08-01	221112	02/06/2012 ACT	2,250 MW COAL FIRED POWER PLANT	PULVERIZED COAL FIRED BOILER	COAL	7725	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNER (LNB), SEPARATED OVERFIRE AIR (SOFA) SYSTEM,	0.24	LB/MMBTU	30-DAY ROLLING AVG	BACT-PSD	0			0		
CA-1206	STOCKTON COGEN COMPANY	APMC STOCKTON COGEN	CA	SJ 85-04	221112	09/16/2011 ACT	49.9 MW COGENERATION POWER PLANT OWNED BY AIR PRODUCTS MANUFACTURING CORPORATION (APMC) STOCKTON COGEN AND LOCATED IN STOCKTON, CALIFORNIA	CIRCULATING FLUIDIZED BED BOILER	COAL	730	MMBTU/H	Nitrogen Oxides (NOx)	LOW BED TEMPERATUR STAGED COMBUSTION; SELECTIVE NON-CATALYTIC REDUCTION (SNCR)	50	PPM	@3% O2, 3-HR AVG	BACT-PSD	42	LB/H	3-HR AVG	0		
MI-0399	DETROIT EDISON--MONROE	DETROIT EDISON	MI	93-09A	221112	12/21/2010 ACT	Utility--Coal fired power plant	Boiler Units 1, 2, 3 and 4	Coal	7624	MMBTU/H	Nitrogen Oxides (NOx)	Staged combustion, low-NOx burners, overfire air, and SCR.	0.08	LB/MMBTU	EACH, 12-MONTH ROLLING AVG.	BACT-PSD	222.6	T/MO	EACH, 12-MONTH ROLLING AVG.	0		
MI-0400	WOLVERINE POWER	WOLVERINE POWER SUPPLY COOPERATIVE, INC.	MI	317-07	221112	06/29/2011 ACT	Coal-fired power plant.	2 Circulating Fluidized Bed Boilers (CFB1 & CFB2)	Petcoke/coal	3030	MMBTU/H EACH	Nitrogen Oxides (NOx)	SNCR (Selective Non-Catalytic Reduction)	1	LB/MW-H	GROSS OUTPUT; EACH; 30 D ROLL. AVG; NSPS	BACT-PSD	281.1	LB/H	EACH; 24H ROLL.AVG.; BACT	0		
MI-0400	WOLVERINE POWER	WOLVERINE POWER SUPPLY COOPERATIVE, INC.	MI	317-07	221112	06/29/2011 ACT	Coal-fired power plant.	2 Circulating Fluidized Bed Boilers (CFB1 & CFB2) -	Petcoke/coal	3030	MMBTU/H each	Nitrogen Oxides (NOx)	SNCR (Selective Non-Catalytic Reduction)	0.07	LB/MMBTU	EACH, 30 D ROLLING AVG; BACT	BACT-PSD	0			0		
ND-0026	M.R. YOUNG STATION	MINNKOTA POWER COOPERATIVE	ND	PTC12003	221112	03/08/2012 ACT	Two lignite fired cyclone boilers.	Cyclone Boilers, Unit 1	Lignite	3200	MMBTU/H	Nitrogen Oxides (NOx)	SNCR plus separated over fire air	0.36	LB/MMBTU	30 DAY ROLLING AVERAGE	BACT-PSD	2070.2	LB/H	24 HOUR AV DURING STARTUP	0		
ND-0026	M.R. YOUNG STATION	MINNKOTA POWER COOPERATIVE	ND	PTC12003	221112	03/08/2012 ACT	Two lignite fired cyclone boilers.	Cyclone Boilers, Unit 2	Lignite	6300	MMBTU/H	Nitrogen Oxides (NOx)	SNCR plus separated over fire air	0.35	LB/MMBTU	30 DAY ROLLING AVERAGE	BACT-PSD	3995.6	LB/H	24 HOUR AV DURING STARTUP	0		
OK-0151	SOONER GENERATING STATION	O G AND E	OK	2010-338-C(M-1)PSD	221112	01/17/2013 ACT	The facility is an electricity generation plant (SIC Code 4911) located in an attainment area. The facility is currently operating under Permit No. 2010-338-TVR2 issued November 21, 2011.	COAL-FIRED BOILERS	COAL	550	MW	Nitrogen Oxides (NOx)	LOW-NOx BURNERS AND OVERFIRE AIR.	0.15	LB/MMBTU	30-DAY AVG	BART	0			0		
OK-0152	MUSKOGEE GENERATING STATION	O G AND E	OK	2005-271-C(M-5)PSD	221112	01/30/2013 ACT	The Muskogee Generating Station utilizes sub-bituminous coal, natural gas, and some waste products (used oil-sorb, used antifreeze, used solvents, used oil, chemical cleaning wastes, hazardous waste fuel, activated carbon, demineralizer resin, and	COAL-FIRED BOILER	COAL	550	MW	Nitrogen Oxides (NOx)	LOW-NOx BURNERS AND OVERFIRE AIR	0.15	LB/MMBTU	30-DAY AVG	BART	0			0		
TX-0554	COLETO CREEK UNIT 2	COLETO CREEK	TX	PSDTX1118 AND 83778	221112	05/03/2010 ACT	Coal-fired boiler	Coal-fired Boiler Unit 2	PRB coal	6670	MMBTU/H	Nitrogen Oxides (NOx)	low-NOx burners with OFA, Selective Catalytic Reduction	0.06	LB/MMBTU	ROLLING 30 DAY AVG	BACT-PSD	0.05	LB/MMBTU	ROLLING 12 MONTH AVG	0		
TX-0556	HARRINGTON STATION UNIT 1 BOILER	SOUTHWESTERN PUBLIC SERVICE COMPANY	TX	PSDTX631M1 AMD 1388	221112	01/15/2010 ACT	The Southwestern Public Service Company (Xcel), the operator of a 3,630 MMBtu/hr coal fired electrical generating facility, is seeking authorization to install modifications to the Unit 1 Boiler at the Harrington Station Boiler Unit 1 in conjunction with a federally-	Unit 1 Boiler	Coal	3630	MMBTU/H	Nitrogen Oxides (NOx)	Separated overfire air windbox system; low-NOx burner tips and additional ya control to the burners.	1452	LB/H		BACT-PSD	0			0		
TX-0557	LIMESTONE ELECTRIC GENERATING STATION	NRG TEXAS POWER LLC	TX	PSDTX371M4 AND 8576	221112	02/01/2010 ACT	NRG Texas Power LLC (NRG) operates two coal and petroleum coke-fired steam/electric units, otherwise known as Limestone Units 1 and 2, which were originally permitted to operate in September 1981. These units are Combustion Engineering tangentially-fired,	LMS Units 1 and 2	Coal	9061	MMBtu/H	Nitrogen Oxides (NOx)	Tuning of existing low-NOx firing system to induce deeper state combustion.	0.25	LB/MMBTU	30-DAY	BACT-PSD	0			0		
*TX-0577	WHITE STALLION ENERGY CENTER	WHITE STALLION ENERGY CENTER, LLC	TX	86088, PAL26, HAP28, PSDTX1160	221112	12/16/2010 ACT	WSEC proposes to construct and operate new steam-electric utility generating facilities using four circulating fluidized bed (CFB) boilers, each with a design maximum heat input of 3,300 million British thermal units per hour (MMBtu/hr) and 300 MW net electric	CFB BOILER	COAL & PET COKE	3300	MMBTU/H	Nitrogen Oxides (NOx)	CFB AND SNCR	0.07	LB NOX/MMBTU	30-DAY ROLLING	BACT-PSD	0.1	LB NOX/MMBTU	1-HR	0		
TX-0585	TENASKA TRAILBLAZER ENERGY CENTER	TENASKA TRAILBLAZER PARTNERS LLC	TX	PSDTX1123 AND HAP13, 84167	221112	12/30/2010 ACT	Coal-fired electric generating facility	Coal-fired Boiler	Sub-bituminous coal	8307	MMBTU/H	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	0.05	LB/MMBTU	12-MONTH ROLLING	BACT-PSD	0.06	LB/MMBTU	30-DAY ROLLING	0		

Appendix A.2

RBLC Search for Coal-Fired Utility Boilers for SO_2

Minnesota Power - Taconite Harbor Energy Center
Regional Haze RFI
Appendix A-2: RBLC Search for Coal-Fired Utility Boilers for SO_2

Pollutant Name: SO_2

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
MI-0400	WOLVERINE POWER	WOLVERINE POWER SUPPLY COOPERATIVE, INC.	MI	317-07	221112	06/29/2011 ACT	Coal-fired power plant.	2 Circulating Fluidized Bed Boilers (CFB1 & CFB2)	Petcoke/coal	3030	MMBTU/H EACH	Sulfur Dioxide (SO2)	Dry flue gas desulfurization (spray dry absorber or polishing scrubber).	303	LB/H	EACH; 24-H ROLL.AVG.; BACT & SIP	BACT-PSD	1.4	LB/MW-H	GROSS OUTPUT; EACH; 30D ROLL.AVG.	0		
MI-0400	WOLVERINE POWER	WOLVERINE POWER SUPPLY COOPERATIVE, INC.	MI	317-07	221112	06/29/2011 ACT	Coal-fired power plant.	2 Circulating Fluidized Bed Boilers (CFB1 & CFB2) -	Petcoke/coal	3030	MMBTU/H each	Sulfur Dioxide (SO2)	Dry flue gas desulfurization (spray dry absorber or polishing scrubber).	0.06	LB/MMBTU	EACH; 30D ROLL.AVG.; BACT&SIP; EXC. SS	BACT-PSD	0.05	LB/MMBTU	EACH;12-MO ROLL.AVG.; BACT&SIP; EXC.SS	0		
AZ-0055	NAVAJO GENERATING STATION	SALT RIVER PROJECT AGRICULTURAL AND POWER DISTRICT	AZ	AZ 08-01	221112	02/06/2012 ACT	2,250 MW COAL FIRED POWER PLANT	PULVERIZED COAL FIRED BOILER	COAL	7725	MMBTU/H	Sulfur Dioxide (SO2)	FLUE GAS DESULFURIZATION (FGD), SCRUBBER	0			BART	0			0		
AZ-0055	NAVAJO GENERATING STATION	SALT RIVER PROJECT AGRICULTURAL AND POWER DISTRICT	AZ	AZ 08-01	221112	02/06/2012 ACT	2,250 MW COAL FIRED POWER PLANT	PULVERIZED COAL FIRED BOILER	COAL	7725	MMBTU/H	Sulfur Dioxide (SO2)	FLUE GAS DESULFURIZATION (FGD), SCRUBBER	0			BART	0			0		
AZ-0055	NAVAJO GENERATING STATION	SALT RIVER PROJECT AGRICULTURAL AND POWER DISTRICT	AZ	AZ 08-01	221112	02/06/2012 ACT	2,250 MW COAL FIRED POWER PLANT	PULVERIZED COAL FIRED BOILER	COAL	7725	MMBTU/H	Sulfur Dioxide (SO2)	FLUE GAS DESULFURIZATION (FGD), SCRUBBER	0			BART	0			0		
*TX-0577	WHITE STALLION ENERGY CENTER	WHITE STALLION ENERGY CENTER, LLC	TX	86088, PAL26, HAP28, PSDTX1160	221112	12/16/2010 ACT	WSEC proposes to construct and operate new steam-electric utility generating facilities using four circulating fluidized bed (CFB) boilers, each with a design maximum heat input of 3,300 million British thermal units per hour (MMBtu/hr) and 300 MW net electric	CFB BOILER	COAL & PET COKE	3300	MMBTU/H	Sulfur Dioxide (SO2)	LIMESTONE BED CFB AND LIME SPRAY DRYER PERMIT DESIGN SULFUR CONTENT OF ILL BASIN COAL IS 3.9 WT% AND OF PET COKE 4.3 AVG/6.0 MAX HI WEIGHTING OF LIMITS	0.114	LB SO2/MMBTU	PET COKE 30-DAY ROLLING	BACT-PSD	0.086	LB SO2/MMBTU	PET COKE 12-MO ROLLING	0.063	LB SO2/MMBTU	COAL 30-DAY & 12-MO ROLLING
KY-0100	J.K. SMITH GENERATING STATION	EAST KENTUCKY POWER COOPERATIVE, INC	KY	V-05-070 R3	221112	04/09/2010 ACT	NEW CFB EGU BECAUSE OF A LEGAL CHALLENGE OUTSIDE OF THE TITLE V PROCEDURES, PERMITTEE AGREED TO TERMINATE CONSTRUCTION AUTHORITY FOR PROJECT. R4 TO THIS PERMIT REMOVES CONSTRUCTION AURTHORITY, AND THE PERMIT MAY	CIRCULATING FLUIDIZED BED BOILER CFB1 AND CFB2	COAL	3000	MMBTU/H	Sulfur Dioxide (SO2)	LIMESTONE INJECTION (CFB)AND A FLASH DRYER ABSORBER WITH FRESH LIME INJECTION	0.075	LB/MMBTU	30 DAY AVERAGE	BACT-PSD	225	LB/H	24 HOUR BLOCK	0		
CA-1206	STOCKTON COGEN COMPANY	APMC STOCKTON COGEN	CA	SJ 85-04	221112	09/16/2011 ACT	49.9 MW COGENERATION POWER PLANT OWNED BY AIR PRODUCTS MANUFACTURING CORPORATION (APMC) STOCKTON COGEN AND LOCATED IN STOCKTON, CALIFORNIA	CIRCULATING FLUIDIZED BED BOILER	COAL	730	MMBTU/H	Sulfur Dioxide (SO2)	LIMESTONE INJECTION W/ A MINIMUM REMOVAL EFFICIENCY OF 70% (3-HR AVG) TO BE MAINTAINED AT ALL TIMES	59	LB/H	8-HR AVG	BACT-PSD	100	LB/H	3-HR AVG	0		
TX-0554	COLETO CREEK UNIT 2	COLETO CREEK	TX	PSDTX1118 AND 83778	221112	05/03/2010 ACT	Coal-fired boiler	Coal-fired Boiler Unit 2	PRB coal	6670	MMBTU/H	Sulfur Dioxide (SO2)	Spray Dry Adsorber/Fabric Filter	0.06	LB/MMBTU	30-DAY ROLLING	BACT-PSD	0.06	LB/MMBTU	12-MONTH ROLLING	0		
TX-0601	GIBBONS CREEK STEAM ELECTRIC STATION	TEXAS MUNICIPAL POWER AGENCY	TX	5699 AND PSDTX18M2	221122	10/28/2011 ACT	one 5,060 MMBtu/h boiler burning natural gas, lignite, coal, and a blend of lignite or coal with petroleum coke	Boiler	Coal	5060	MMBtu/h	Sulfur Dioxide (SO2)	Wet Flue Gas Desulfurization	1.2	LB/MMBTU		BACT-PSD	1771	LB/H		6052	T/YR	
MI-0399	DETROIT EDISON--MONROE	DETROIT EDISON	MI	93-09A	221112	12/21/2010 ACT	Utility--Coal fired power plant	Boiler Units 1, 2, 3 and 4	Coal	7624	MMBTU/H	Sulfur Dioxide (SO2)	Wet flue gas desulfurization.	0.107	LB/MMBTU	EACH, 24-H ROLL. AVG.	BACT-PSD	815.8	LB/H	EACH, 24-H ROLL. AVG.	0		
TX-0585	TENASKA TRAILBLAZER ENERGY CENTER	TENASKA TRAILBLAZER PARTNERS LLC	TX	PSDTX1123 AND HAP13, 84167	221112	12/30/2010 ACT	Coal-fired electric generating facility	Coal-fired Boiler	Sub-bituminous coal	8307	MMBTU/H	Sulfur Dioxide (SO2)	Wet limestone scrubber	0.06	LB/MMBTU	30-DAY ROLLING	BACT-PSD	0.06	LB/MMBTU	12-MONTH ROLLING	0		

Appendix B

Unit-Specific Screening Level Cost Summary for NO_X Control Measures

Minnesota Power - Taconite Harbor Energy Center
Regional Haze RFI
Control Equipment Cost Evaluation

NOTE: Costs presented per unit but projects would only be done on both units together

EQUIPMENT DETAILS

Emission Unit Number	**Boilers No. 1 and No. 2**	
Control Equipment Type	**Burner Modifications - LNB coal tip replacement only (NOx improvement)**	
Details	Replace coal tip with nozzle tip that changes boiler fireball shape	
Max Operating Design	900	MMBtu/hr
Expected Utilization Rate	100%	
Expected Annual Hours of Operation	8,760	Hours
Annual Interest Rate	3.25%	Bank Prime Rate for July 16, 2020 from https://www.federalreserve.gov/releases/h15/.
Expected Equipment Life	10	yrs

CAPITAL COSTS

Direct Capital Costs				
Purchased Equipment (A) (1)				
Purchased Equipment Costs (A)		Engineering judgement based on previous project by Minnesota Power	$	500,000
Instrumentation	10.00%	of control device cost (A)	$	50,000
Sales Taxes	6.875%	of control device cost (A)	$	34,375
Freight	5.0%	of control device cost (A)	$	25,000
Purchased Equipment Total (B)			**$**	**609,375**
Installation				
Foundations & supports	0%	Conservatively excluded from analysis	$	-
Handling & erection	0%	Conservatively excluded from analysis	$	-
Electrical	0%	Conservatively excluded from analysis	$	-
Piping	0%	Conservatively excluded from analysis	$	-
Insulation	0%	Conservatively excluded from analysis	$	-
Painting	0%	Conservatively excluded from analysis	$	-
Installation Subtotal Standard Expenses			**$**	**-**
Site Preparation, as required	0%	None required	$	-
Buildings, as required	0%	None required	$	-
Site Specific - Other	0%	None required	$	-
Total Site Specific Costs			$	-
Installation Total			**$**	**-**
Total Direct Capital Cost, DC			**$**	**609,375**
Indirect Capital Costs				
Engineering, supervision	0%	Conservatively excluded from analysis	$	-
Construction & field expenses	0%	Conservatively excluded from analysis	$	-
Contractor fees	0%	Conservatively excluded from analysis	$	-
Start-up	0%	Conservatively excluded from analysis	$	-
Performance test	0%	Conservatively excluded from analysis	$	-
Model Studies	0%	Conservatively excluded from analysis	$	-
Contingencies	0%	Conservatively excluded from analysis	$	-
Total Indirect Capital Costs, IC			**$**	**-**
Total Capital Investment (TCI) = DC + IC			**$**	**609,375**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**$**	**609,375**

OPERATING COSTS

NOTE: *These are incremental "add-on" costs of the specific project, not all-in costs (for example, additional labor hours to run the equipment, additional reagent needed, additional tons of waste generated, etc.)*

Item	**Unit Cost**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Comments**		
Direct Annual Operating Costs, DC							
Operating Labor							
Operator	$ 60.00	$/Hr	0.00	hr/8 hr shift	No additional labor costs	$	-
Supervisor	15%	of Op. Labor			15% of Operator Costs	$	-
Maintenance							
Maintenance Labor	$ 60.00	$/Hr	1.00	hr/8 hr shift	$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 1 hr/8 hr shift, 8,760 hr/yr, Based on average annual maintenenance cost for labor and material	$	65,700
Maintenance Materials	100%	of Maint Labor			of maintenance labor costs	$	65,700
Utilities, Supplies, Replacements & Waste Management							
Fuel Penalty	$ 13.640	/ton coal	0	ton coal/yr	No impacts expected - engineering judgment	$	-
Electricity	$ 0.036	/kw-hr	0	kw-hr/yr	No impacts expected - engineering judgment	$	-
Water	$ 0.004	/mgal	0	mgal/yr	No impacts expected - engineering judgment	$	-
Compressed Air	$ 0.367	/mscf	0	mscf/yr	No impacts expected - engineering judgment	$	-
Wastewater Treatment	$ 1.957	/mgal	0	mgal/yr	No impacts expected - engineering judgment	$	-
Solid Waste Disposal	$ 48.800	/ton	0	ton/year	No impacts expected - engineering judgment	$	-
Hazardous Waste Disposal	$ 488.000	/ton	0	ton/year	No impacts expected - engineering judgment	$	-
Waste Transport	$ 0.652	/ton-mi	0	ton-mi/yr	No impacts expected - engineering judgment	$	-
Lime	$ 290.000	/ton	0	ton/yr	No impacts expected - engineering judgment	$	-
Ammonia	$ 0.293	/gal	0	gal/yr	No impacts expected - engineering judgment	$	-
Total Annual Direct Operating Costs						**$**	**131,400**
Indirect Operating Costs							
Overhead				0%	Conservatively excluded from analysis	$	-
Administration (2% total capital costs)				2%	of total capital costs (TCI)	$	12,188
Property tax (1% total capital costs)				1%	of total capital costs (TCI)	$	6,094
Insurance (1% total capital costs)				1%	of total capital costs (TCI)	$	6,094
Capital Recovery				0.1187	capital recovery factor for a 10-year equipment life and 3.3% interest rate	$	72,352
Total Annual Indirect Operating Costs						**$**	**96,727**
Total Annual Cost (Direct Operating Cost + Indirect Operating Cost)						**$**	**228,127**

Minnesota Power - Taconite Harbor Energy Center
Regional Haze RFI
Control Equipment Cost Evaluation

NOTE: Costs presented per unit but projects would only be done on both units together

EQUIPMENT DETAILS

Emission Unit Number	**Boilers No. 1 and No. 2**	
Control Equipment Type	**Enhance SNCR/ROFA (NOx improvement)**	
Details	Add CCOFA with tilt and yaw, change SNCR injection ports and locations, add additional ROFA system controls	
Max Operating Design	900	MMBtu/hr
Expected Utilization Rate	100%	
Expected Annual Hours of Operation	8,760	Hours
Annual Interest Rate	3.25%	Bank Prime Rate for July 16, 2020 from https://www.federalreserve.gov/releases/h15/.
Expected Equipment Life	20	yrs

CAPITAL COSTS

Direct Capital Costs			
Purchased Equipment (A) (1)			
Purchased Equipment Costs (A)		Engineering judgement based on previous project by Minnesota Power	$ 1,000,000
Instrumentation	10.00%	of control device cost (A)	$ 100,000
Sales Taxes	6.875%	of control device cost (A)	$ 68,750
Freight	5.0%	of control device cost (A)	$ 50,000
Purchased Equipment Total (B)			**$ 1,218,750**
Installation			
Foundations & supports	0%	Conservatively excluded from analysis	$ -
Handling & erection	0%	Conservatively excluded from analysis	$ -
Electrical	0%	Conservatively excluded from analysis	$ -
Piping	0%	Conservatively excluded from analysis	$ -
Insulation	0%	Conservatively excluded from analysis	$ -
Painting	0%	Conservatively excluded from analysis	$ -
Installation Subtotal Standard Expenses			**$ -**
Site Preparation, as required	0%	None required	$ -
Buildings, as required	0%	None required	$ -
Site Specific - Other	0%	None required	$ -
Total Site Specific Costs			$ -
Installation Total			**$ -**
Total Direct Capital Cost, DC			**$ 1,218,750**
Indirect Capital Costs			
Engineering, supervision	0%	Conservatively excluded from analysis	$ -
Construction & field expenses	0%	Conservatively excluded from analysis	$ -
Contractor fees	0%	Conservatively excluded from analysis	$ -
Start-up	0%	Conservatively excluded from analysis	$ -
Performance test	0%	Conservatively excluded from analysis	$ -
Model Studies	0%	Conservatively excluded from analysis	$ -
Contingencies	0%	Conservatively excluded from analysis	$ -
Total Indirect Capital Costs, IC			**$ -**
Total Capital Investment (TCI) = DC + IC			**$ 1,218,750**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**$ 1,218,750**

OPERATING COSTS

NOTE: These are incremental "add-on" costs of the specific project, not all-in costs (for example, additional labor hours to run the equipment, additional reagent needed, additional tons of waste generated, etc.)

Item	Unit Cost	Unit of Measure	Use Rate	Unit of Measure	Comments	
Direct Annual Operating Costs, DC						
Operating Labor						
Operator	$ 60.00	$/Hr	1.00	hr/8 hr shift	$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 1 hr/8 hr shift, 8,760 hr/yr	$ 65,700
Supervisor	15%	of Op. Labor			15% of Operator Costs	$ 9,855
Maintenance						
Maintenance Labor	$ 60.00	$/Hr	1.00	hr/8 hr shift	$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 1 hr/8 hr shift, 8,760 hr/yr	$ 65,700
Maintenance Materials	100%	of Maint Labor			of maintenance labor costs	$ 65,700
Utilities, Supplies, Replacements & Waste Management						
Fuel Penalty	$ 13.640	/ton coal	0	ton coal/yr	no impacts expected- engineering judgement	$ -
Electricity	$ 0.036	/kw-hr	0	kw-hr/yr	no impacts expected- engineering judgement	$ -
Water	$ 0.004	/mgal	0	mgal/yr	no impacts expected- engineering judgement	$ -
Compressed Air	$ 0.367	/mscf	0	mscf/yr	no impacts expected- engineering judgement	$ -
Wastewater Treatment	$ 1.957	/mgal	0	mgal/yr	no impacts expected- engineering judgement	$ -
Solid Waste Disposal	$ 48.800	/ton	0	ton/year	no impacts expected- engineering judgement	$ -
Hazardous Waste Disposal	$ 488.000	/ton	0	ton/year	no impacts expected- engineering judgement	$ -
Waste Transport	$ 0.652	/ton-mi	0	ton-mi/yr	no impacts expected- engineering judgement	$ -
Lime	$ 290.000	/ton	0	ton/yr	no impacts expected- engineering judgement	$ -
Ammonia	$ 0.293	/gal	12,000	gal/yr	engineering judgement	$ 3,516
Total Annual Direct Operating Costs						**$ 210,471**

Indirect Operating Costs			
Overhead	0%	Conservatively excluded from analysis	$ -
Administration (2% total capital costs)	2%	of total capital costs (TCI)	$ 24,375
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	$ 12,188
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	$ 12,188
Capital Recovery	0.0688	capital recovery factor for a 20-year equipment life and 3.3% interest rate	$ 83,824
Total Annual Indirect Operating Costs			**$ 132,574**
Total Annual Cost (Direct Operating Cost + Indirect Operating Cost)			**$ 343,045**

Appendix C

Unit-Specific Screening Level Cost Summary for SO_2 Control Measures

Minnesota Power - Taconite Harbor Energy Center
Regional Haze RFI
Control Equipment Cost Evaluation

NOTE: Costs presented per unit but projects would only be done on both units together

EQUIPMENT DETAILS

Emission Unit Number	**Boilers No. 1 and No. 2**	
Control Equipment Type	**Enhance Lime/SBC Injection (SO2 improvement)**	
Details	CFD modeling to adjust injection port locations and resolve operational problems	
Max Operating Design	900	MMBtu/hr
Expected Utilization Rate	100%	
Expected Annual Hours of Operation	8,760	Hours
Annual Interest Rate	3.25%	Bank Prime Rate for July 16, 2020 from https://www.federalreserve.gov/releases/h15/.
Expected Equipment Life	20	yrs

CAPITAL COSTS

Direct Capital Costs				
Purchased Equipment (A) (1)				
Purchased Equipment Costs (A)		Engineering judgement based on previous project by Minnesota Power	$	3,000,000
Instrumentation	10.00%	of control device cost (A)	$	300,000
Sales Taxes	6.875%	of control device cost (A)	$	206,250
Freight	5.0%	of control device cost (A)	$	150,000
Purchased Equipment Total (B)			**$**	**3,656,250**
Installation				
Foundations & supports	0%	Conservatively excluded from analysis	$	-
Handling & erection	0%	Conservatively excluded from analysis	$	-
Electrical	0%	Conservatively excluded from analysis	$	-
Piping	0%	Conservatively excluded from analysis	$	-
Insulation	0%	Conservatively excluded from analysis	$	-
Painting	0%	Conservatively excluded from analysis	$	-
Installation Subtotal Standard Expenses			**$**	**-**
Site Preparation, as required	0%	None required	$	-
Buildings, as required	0%	None required	$	-
Site Specific - Other	0%	None required	$	-
Total Site Specific Costs			$	-
Installation Total			**$**	**-**
Total Direct Capital Cost, DC			**$**	**3,656,250**
Indirect Capital Costs				
Engineering, supervision	0%	None required	$	-
Construction & field expenses	0%	None required	$	-
Contractor fees	0%	None required	$	-
Start-up	0%	None required	$	-
Performance test	0%	None required	$	-
Model Studies	0%	None required	$	-
Contingencies	0%	None required	$	-
Total Indirect Capital Costs, IC			**$**	**-**
Total Capital Investment (TCI) = DC + IC			**$**	**3,656,250**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**$**	**3,656,250**

OPERATING COSTS

__NOTE:__ These are incremental "add-on" costs of the specific project, not all-in costs (for example, additional labor hours to run the equipment, additional reagent needed, additional tons of waste generated, etc.)

Item	Unit Cost	Unit of Measure	Use Rate	Unit of Measure	Comments		
Direct Annual Operating Costs, DC							
Operating Labor							
Operator	$ 60.00	$/Hr	1.00	hr/8 hr shift	$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 1 hr/8 hr shift, 8,760 hr/yr	$	65,700
Supervisor	15%	of Op. Labor			15% of Operator Costs	$	9,855
Maintenance							
Maintenance Labor	$ 60.00	$/Hr	2.00	hr/8 hr shift	$60/Hr value is from EPA's cost spreadsheet for SCR controls and includes benefits, 2 hr/8 hr shift, 8,760 hr/yr	$	131,400
Maintenance Materials	100%	of Maint Labor			of maintenance labor costs	$	131,400
Utilities, Supplies, Replacements & Waste Management							
Fuel Penalty	$ 13.640	/ton coal	0	ton coal/yr	No impacts expected- engineering judgement	$	-
Electricity	$ 0.036	/kw-hr	0	kw-hr/yr	No impacts expected- engineering judgement	$	-
Water	$ 0.004	/mgal	0	mgal/yr	No impacts expected- engineering judgement	$	-
Compressed Air	$ 0.367	/mscf	0	mscf/yr	No impacts expected- engineering judgement	$	-
Wastewater Treatment	$ 1.957	/mgal	0	mgal/yr	No impacts expected- engineering judgement	$	-
Solid Waste Disposal	$ 48.800	/ton	0	ton/year	No impacts expected- engineering judgement	$	-
Hazardous Waste Disposal	$ 488.000	/ton	0	ton/year	No impacts expected- engineering judgement	$	-
Waste Transport	$ 0.652	/ton-mi	0	ton-mi/yr	No impacts expected- engineering judgement	$	-
Lime	$ 290.000	/ton	2,190	ton/yr	Engineering judgement	$	635,100
Ammonia	$ 0.293	/gal	0	gal/yr	No impacts expected- engineering judgement	$	-
Total Annual Direct Operating Costs						**$**	**973,455**
Indirect Operating Costs							
Overhead				0%	Conservatively excluded from analysis	$	-
Administration (2% total capital costs)				2%	of total capital costs (TCI)	$	73,125
Property tax (1% total capital costs)				1%	of total capital costs (TCI)	$	36,563
Insurance (1% total capital costs)				1%	of total capital costs (TCI)	$	36,563
Capital Recovery				0.0688	capital recovery factor for a 20-year equipment life and 3.3% interest rate	$	251,473
Total Annual Indirect Operating Costs						**$**	**397,723**
Total Annual Cost (Direct Operating Cost + Indirect Operating Cost)						**$**	**1,371,178**

MINNESOTA POLLUTION
CONTROL AGENCY

520 Lafayette Road North | St. Paul, Minnesota 55155-4194 | 651-296-6300
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January 29, 2020

Jaime L. Johnson, Manager - Environmental
ArcelorMittal Minorca Mine Inc.
5950 Old Highway 53 N
Virginia, MN 55792

RE: Request for Information - Regional Haze Rule, Reasonable Progress, Four Factor Analysis

Dear Ms. Johnson:

The Minnesota Pollution Control Agency (MPCA) is currently preparing information for the second planning period (Round 2) comprehensive update to Minnesota's Regional Haze State Implementation Plan (SIP) as required by the Regional Haze Rule (40 CFR § 51.308). States are responsible for developing a Regional Haze SIP that addresses regional haze in each Class I area located within the state and in each Class I area located outside the state which may be affected by emissions from sources within the state. The Regional Haze SIP is required to identify existing facilities that cause or contribute to visibility impairment; analyze, identify, and apply federally-enforceable control strategies for those sources; and periodically demonstrate reasonable progress toward reaching visibility goals. States are also responsible for periodic comprehensive updates to their Regional Haze SIP that address these same topics. Minnesota's Round 2 Regional Haze SIP must be submitted to the U.S. Environmental Protection Agency (U.S. EPA) by July 31, 2021.

Minnesota has two Class I areas within its borders, the Boundary Waters Canoe Area Wilderness (BWCA) and Voyageurs National Park (Voyageurs). Other nearby Class I areas include Isle Royale National Park in Michigan. Therefore, Minnesota must prepare a Regional Haze SIP that identifies sources that cause or contribute to visibility impairment in these areas. To meet the core requirements for regional haze for these areas, Minnesota must submit a SIP that contains the plan elements and supporting documentation for all required analyses identified in 40 CFR § 51.308(f).

In the first planning period (Round 1), the focus of the Regional Haze Rule was on establishing Best Available Retrofit Technology (BART) for certain older sources and reasonable progress towards national visibility goals. In Round 2, there are no BART requirements; therefore, the focus is on making reasonable progress. The U.S. Environmental Protection agency has defined the methodology that states must use to determine what measures are necessary to make reasonable progress in 40 CFR § 51.308(f)(2). At minimum, the reasonable progress analysis must use the four factors identified in 40 CFR § 51.308(f)(2)(i) to evaluate and determine the emission reduction measures necessary to make reasonable progress. The four factors are:

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

Data from the IMPROVE monitoring sites at BWCA and Voyageurs indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X).

You are receiving this letter because your facility was identified as a significant source of NO_X and SO_2 and is located close enough to the BWCA or Voyageurs to potentially cause or contribute to visibility impairment in these Class I areas. Therefore, the MPCA requests that you prepare a "Four Factor Analysis" for the following emission units:

1. Indurating Machine (EQUI 38 / EU 026) that addresses emissions of NO_X and SO_2

The analysis should be prepared using the U.S. Environmental Protection Agency guidance[1] that provides recommendations for how each of the factors should be determined.

Preparation of the comprehensive update to Minnesota's Regional Haze SIP will require extensive planning and review of sources in Minnesota. The MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to prepare the Regional Haze SIP. The MPCA expects air quality modeling of potential regional emissions reductions will be conducted beginning in spring 2020. I appreciate your attention to this matter and request that you **submit the Four Factor Analysis by July 31, 2020**.

If you have any questions regarding this matter, or would like to request a meeting to further discuss the contents of this letter, please contact me by phone at 651-757-2653 or by email at Hassan.Bouchareb@state.mn.us.

Sincerely,

Hassan Bouchareb

This document has been electronically signed.

Hassan M. Bouchareb
Engineer
Environmental Analysis and Outcomes Division

Cc: Deepa de Alwis, MPCA
Cory Boeck, MPCA
Frank Kohlasch, MPCA
Agency Interest ID 699

Address questions and submittals requested above to:

Hassan M. Bouchareb
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155-4194
(651) 757-2653
Hassan.Bouchareb@state.mn.us

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[1] **U.S. Environmental Protection Agency.** *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 20, 2019, https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

ArcelorMittal

May 29, 2020

Hassan M. Bouchareb
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155-4194

Re: ArcelorMittal Minorca Mine Inc.
Request for Information – Four Factor Analysis

Mr. Bouchareb,

ArcelorMittal Minorca Mine Inc. (Minorca) has prepared the enclosed Regional Haze Four-Factor Analysis Applicability Evaluation (Evaluation) in response to the Minnesota Pollution Control Agency's (MPCA) January 29, 2020 request for information and a Four Factor Analysis for the natural gas fired indurating machine (EQUI 38/EU 026).

Minorca respectfully requests MPCA timely withdraw its request for Minorca to prepare a four-factor analysis for the natural gas fired indurating machine which is already equipped with Newly Engineered Site-Specific Low NO_X Burner Technology and Taconite MACT scrubbers. The Evaluation provides evidence for MPCA to exclude Minorca from the group of sources analyzed for control measures for the second implementation period and to withdraw its request for a Four Factor Analysis.

Should you have any questions or comments regarding this submittal, please contact Jaime Johnson, Environmental Manager, by telephone at 218-305-3337, or via email at Jaime.Johnson@arcelormittal.com.

Sincerely,

Robb A. Peterson
Operations Manager

cc: Jaime L. Johnson (ArcelorMittal USA)
Rich Zavoda (ArcelorMittal USA)

Regional Haze Four-Factor Analysis Applicability Evaluation

Natural Gas Fired Indurating Machine Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT Scrubbers (EQUI 28/EU 026)

Prepared for
ArcelorMittal Minorca Mine Inc.

May 29, 2020

325 South Lake Avenue
Duluth, MN 55802
218.529.8200
www.barr.com

Regional Haze Four-Factor Analysis Applicability Evaluation

May 29, 2020

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Appendix A Visibility Impacts

1 Executive Summary

On January 29, 2020 the Minnesota Pollution Control Agency (MPCA) submitted a Request for Information (RFI) Letter[1] to ArcelorMittal Minorca Mine, Inc. (Minorca) to consider potential emissions reduction measures of nitrogen oxides (NO_X) and sulfur dioxide (SO_2) from the facility's indurating furnace by addressing the four statutory factors laid out in 40 CFR 51.308(f)(2)(i), as explained in the August 2019 U.S. EPA Guidance (2019 Guidance)[2]:

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

Emission reduction evaluations addressing these factors are commonly referred to as "four-factor analyses." MPCA set a July 31, 2020 deadline for Minorca to submit a four-factor analysis. The MPCA intends to use the four-factor analyses to evaluate additional control measures as part of the development of the State Implementation Plan (SIP), which must be submitted to United States Environmental Protection Agency (USEPA) by July 31, 2021. The SIP will be prepared to address the second regional haze implementation period, which ends in 2028.

This report considers whether a four-factor analysis is warranted for Minorca because the indurating machine can be classified as an "effectively controlled" source for NO_x and SO_2. The MPCA can exclude such sources for evaluation per the regulatory requirements of the Regional Haze Rule[3] (RHR) and the 2019 Guidance.

This report provides evidence that it would be reasonable for MPCA to exclude Minorca from the group of sources analyzed for control measures for the second implementation period and to withdraw its request for a four-factor analysis for the indurating machine based on the following points (with additional details provided in cited report sections):

- The indurating machine meets the BART-required control equipment installation scenario and is an "effectively controlled" source for NO_x and SO_2. Minorca has BART emission controls and emission limits for NO_X and SO_2 in accordance with 40 CFR 52.1235(b)(1) and 52.1235(b)(2), respectively. The associated BART analyses are provided in the August 2012[4] and October 2015[5] USEPA Federal Implementation Plan (FIP) rulemaking. (see Section 5)

---

[1] January 29, 2020 letter from Hassan Bouchareb of MPCA to ArcelorMittal Minorca Mine Inc.

[2] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[3] USEPA, Regional Haze Rule Requirements – Long Term Strategy for Regional Haze, 40 CFR 52.308(f)(2)

[4] USEPA, Federal Register, 08/15/2012, Page 49308.

[5] USEPA, Federal Register, 10/22/2015, Page 64160.

- The RHR and the 2019 Guidance both give states the ability to focus their analyses in one implementation period on a set of sources that differ from those analyzed in another implementation period. (see Section 2.1.3.2)
- There has been significant progress on visibility improvement in the nearby Class I areas and MPCA's reasonable progress goals should be commensurate with this progress. (see Section 3.1)
- The indurating machine does not materially impact visibility from a theoretical (modeling) and empirical (actual visibility data) basis and should not be required to assess additional emission control measures. (see Section 4)

Additional emission reductions from the indurating machine at Minorca will not contribute meaningfully to further reasonable progress. **Therefore, Minorca respectfully requests MPCA withdraw its request for a four-factor analysis for the natural gas fired indurating machine already equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT scrubbers.**

2 Introduction

Section 2.1 discusses the RFI provided to Minorca by MPCA, pertinent regulatory background for regional haze State Implementation Plans (SIP) development and relevant guidance issued by USEPA to assist States in preparing their SIPs, specifically regarding the selection of sources that must conduct an emissions control evaluation. Section 2.2 provides a description of Minorca's indurating furnace.

2.1 Regulatory Background

2.1.1 Minnesota's Request for Information (RFI)

"Regional haze" is defined at 40 CFR 51.301 as "visibility impairment that is caused by the emission of air pollutants from numerous anthropogenic sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources." The RHR requires state regulatory agencies to submit a series of SIPs in ten-year increments to protect visibility in certain national parks and wilderness areas, known as mandatory Federal Class I areas. The original State SIPs were due on December 17, 2007 and included milestones for establishing reasonable progress towards the visibility improvement goals, with the ultimate goal to achieve natural background visibility by 2064. The initial SIP was informed by best available retrofit technology (BART) analyses that were completed on all BART-subject sources. The second RHR implementation period ends in 2028 and requires development and submittal of a comprehensive SIP update by July 31, 2021.

As part of the second RHR implementation period SIP development, the MPCA sent an RFI to Minorca on January 29, 2020. The RFI stated that data from the IMPROVE (Interagency Monitoring of Protected Visual Environments) monitoring sites at Boundary Waters Canoe Area (BWCA) and Voyageurs National Park (Voyageurs) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of SO_2 and NO_X that react with available ammonia. In addition, emissions from sources in Minnesota could potentially impact Class I areas in nearby states, namely Isle Royale National Park (Isle Royale) in Michigan.[6] As part of the planning process for the SIP development, MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to evaluate regional emission reductions.

The RFI also stated that Minorca was identified as a significant source of NO_X and SO_2 and is located close enough to the BWCA and Voyageurs to potentially cause or contribute to visibility impairment. Therefore, the MPCA requested that Minorca submit a "four-factors analysis" (herein termed as a "four-factor analysis") evaluating potential emissions control measures, pursuant to 40 CFR 51.308(f)(2)(i)[7], by July 31, 2020 for the emission units identified in Table 2-1.

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[6] Although Michigan is responsible for evaluating haze in Isle Royale, it must consult with surrounding states, including Minnesota, on potential cross-state haze pollution impacts.

[7] The four statutory factors are 1) cost of compliance, 2) time necessary for compliance, 3) energy and non-air quality environmental impacts of compliance, and 4) remaining useful life of the source.

Table 2-1 Identified Emission Units

Unit	Unit ID	Applicable Pollutants
Natural Gas Fired Indurating Machine Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT Scrubbers	(EQUI 38/EU 026)	NO_X, SO_2

The RFI to Minorca specified that the "analysis should be prepared using the U.S. Environmental Protection Agency guidance" referring to USEPA guidance as issued on August 20, 2019[8].

2.1.2 SIP Revision Requirements

The regulatory requirements for comprehensive revisions to the SIP are provided in 40 CFR 51.308(f). The next revision must be submitted to USEPA by July 31, 2021 and must include a commitment to submit periodic reports describing progress towards the reasonable progress goals as detailed in 40 CFR 51.308(g). The SIP "must address regional haze in each mandatory Class I Federal area located within the State and in each mandatory Class I Federal area located outside the State that may be affected by emissions from within the State."

Each SIP revision is required to address several elements, including "calculations of baseline, current, and natural visibility conditions; progress to date; and the uniform rate of progress." [9] The baseline conditions are based on monitoring data from 2000 to 2004 while the target conditions for natural visibility are determined using USEPA guidance. The State will then determine the uniform rate of progress (URP) which compares "the baseline visibility condition for the most impaired days to the natural visibility condition for the most impaired days and determine the uniform rate of visibility improvement (measured in deciviews of improvement per year) that would need to be maintained during each implementation period in order to attain natural visibility conditions by the end of 2064."[10]

The SIP revision must also include the "Long-term strategy for regional haze."[11] The strategy "must include the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress" towards the natural visibility goal. There are several criteria that must be considered when developing the strategy, including an evaluation of emission controls (the four-factor analysis) at selected facilities to determine emission reductions necessary to make reasonable progress. The SIP must consider other factors in developing its long-term strategy, including: emission reductions due to other air pollution control programs[12], emission unit retirement and replacement

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[8] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[9] 40 CFR 51.308(f)(1)

[10] 40 CFR 51.308(f)(1)(vi)(A)

[11] 40 CFR 51.308(f)(2)

[12] 51.308(f)(2)(iv)(A)

schedules[13], and the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions during the implementation period[14].

In addition, the SIP must include "reasonable progress goals" that reflect the visibility conditions that are anticipated to be achieved by the end of the implementation period through the implementation of the long term strategy and other requirements of the Clean Air Act (CAA)[15]. The reasonable progress goal is not enforceable but will be considered by USEPA in evaluating the adequacy of the SIP[16].

2.1.3 USEPA Guidance for SIP Development

On August 20, 2019, the USEPA issued "*Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*"[17] USEPA's primary goal in issuing the 2019 Guidance was to help states develop "approvable" SIPs. EPA also stated that the document supports key principles in SIP development, such as "leveraging emission reductions achieved through CAA and other programs that further improve visibility in protected areas."[18]

The 2019 Guidance says SIPs must be "consistent with applicable requirements of the CAA and EPA regulations, and are the product of reasoned decision-making"[19] but also emphasizes States' discretion and flexibility in the development of their SIPs. For instance, the 2019 Guidance states, "A key flexibility of the regional haze program is that a state is *not* required to evaluate all sources of emissions in each implementation period. Instead, a state may reasonably select a set of sources for an analysis of control measures."[20] The 2019 Guidance notes this flexibility to not consider every emission source stems directly from CAA § 169A(b)(2) and 40 CFR § 51.308(f)(2)(i), the section of the RHR the MPCA cites in its letter.[21]

The 2019 Guidance lists eight key process steps that USEPA anticipates States will follow when developing their SIPs. This report focuses on the selection of sources which must conduct a four-factor analysis and references the following guidance elements which impact the selection:

- Ambient data analysis (Step 1), including the progress, degradation and URP glidepath checks (Step 7)
- Selection of sources for analysis (Step 3), with a focus on:
    - Estimating baseline visibility impacts for source selection (Step 3b)

---

[13] 51.308(f)(2)(iv)(C)

[14] 51.308(f)(2)(iv)(E)

[15] 40 CFR 51.308(f)(3)

[16] 40 CFR 51.308(f)(3)(iii)

[17] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[18] Ibid, page 1.

[19] Ibid.

[20] Ibid, page 9 (emphasis added).

[21] Ibid.

- Sources that already have effective emission control technology in place (Step 3f)

2.1.3.1 Ambient Data Analysis

As stated in Section 2.1.2, the RHR requires each state with a Class I area to calculate the baseline, current, and natural visibility conditions as well as to determine the visibility progress to date and the URP. The visibility metric is based on the 20% most anthropogenically impaired days and the 20% clearest days, with visibility being measured in deciviews (dv). The guidance provides the following equation for calculating the Uniform Rate of Progress (URP):[22]

$$\text{URP} = [(\text{2000-2004 visibility})_{\text{20\% most impaired}} - (\text{natural visibility})_{\text{20\% most impaired}}]/60$$

The visibility from 2000-2004 represents the baseline period, and the natural visibility goal is in 2064, which is why the URP is calculated over a 60-year period.

At the end of the SIP development process a State must estimate the visibility conditions for the end of the implementation period and then must complete a comparison of the reasonable progress goals to the baseline visibility conditions and the URP glidepath. The guidance explains that the RHR does not define the URP as the target for "reasonable progress" and further states that if the 2028 estimate is below the URP glidepath, that does not exempt the State from considering the four-factor analysis for select sources.[23] However, the current visibility conditions compared to the URP glidepath will be a factor when determining the reasonable progress goal.

In Section 3, Barr evaluates the visibility improvement progress to date at BWCA, Voyageurs and Isle Royale using the IMPROVE network visibility data from MPCA's website. This analysis was conducted to document the current visibility conditions compared to the URP, which can provide insight into the amount of emission reductions necessary to have the 2028 visibility conditions below the URP.

2.1.3.2 Selection of sources for analysis

The 2019 Guidance emphasizes that the RHR provides flexibility in selecting sources that must conduct an emission control measures analysis:

> "…a state is not required to evaluate all sources of emissions in each implementation period. Instead, a state may reasonably select a set of sources for an analysis of control measures…."[24]

The 2019 Guidance goes on to justify this approach (emphasis added):

> "Selecting a set of sources for analysis of control measures in each implementation period is also consistent with the Regional Haze Rule, which sets up an iterative planning process and anticipates that a state may not need to analyze control measures for all its sources in a given SIP revision. Specifically, section 51.308(f)(2)(i) of the Regional Haze Rule requires a SIP to include a

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[22] Ibid, Page 7.

[23] Ibid, Page 50.

[24] Ibid, Page 9.

> description of the criteria the state has used to determine the sources or groups of sources it evaluated for potential controls. Accordingly, it is reasonable and permissible for a state to distribute its own analytical work, and the compliance expenditures of source owners, over time by addressing some sources in the second implementation period and other sources in later periods. For the sources that are not selected for an analysis of control measures for purposes of the second implementation period, it may be appropriate for a state to consider whether measures for such sources are necessary to make reasonable progress in later implementation periods."[25]

The 2019 Guidance further states that there is not a list of factors that a state must consider when selecting sources to evaluate control measures, but the state must choose factors and apply them in a reasonable way to make progress towards natural visibility. The guidance details several factors that could be considered, including:

- the in-place emission control measures and, by implication, the emission reductions that are possible to achieve at the source through additional measures[26]
- the four statutory factors (to the extent they have been characterized at this point in SIP development)[27]
- potential visibility benefits (also to the extent they have been characterized at this point in SIP development)[28]
- sources already having effective emissions controls in place[29]
- emission reductions at the source due to ongoing air pollution control programs[30]
- in-state emission reductions due to ongoing air pollution control programs that will result in an improvement in visibility[31]

Furthermore, the 2019 Guidance states that "An initial assessment of projected visibility impairment in 2028, considering growth and on-the books controls, can be a useful piece of information for states to consider as they decide how to select sources for control measure evaluation."[32]

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[25] Ibid, Page 9.

[26] Ibid, Page 10.

[27] Ibid.

[28] Ibid.

[29] Ibid, Page 21.

[30] Ibid, Page 22.

[31] Ibid.

[32] Ibid, Page 10.

2.1.3.2.1 Estimating Baseline Visibility Impacts for Source Selection

When selecting sources to conduct an emission control evaluation, the 2019 Guidance says that the state may use a "reasonable surrogate metrics of visibility impacts." The guidance provides the following techniques to consider and says that "other reasonable techniques" may also be considered[33]:

- Emissions divided by distance (Q/d)
- Trajectory analyses
- Residence time analyses
- Photochemical modeling

In regard to documenting the source selection process, the 2019 Guidance states:[34]

> "EPA recommends that this documentation and description provide both a summary of the state's source selection approach and a detailed description of how the state used technical information to select a reasonable set of sources for an analysis of control measures for the second implementation period. The state could include qualitative and quantitative information such as: the basis for the visibility impact thresholds the state used (if applicable), additional factors the state considered during its selection process, and any other relevant information."

In Section 4, Barr presents a trajectory analysis using data from the IMPROVE monitoring network as presented on MPCA's website and photochemical modeling results to demonstrate that it is not appropriate to select the taconite indurating furnaces as sources subject to the emissions control measures analysis because reducing the emissions will not have a large impact on visibility. Section 4 also presents information from the IMPROVE monitoring system which demonstrates that there was not a noticeable improvement in visibility in 2009 when the taconite plants experienced a production curtailment due to a recession which indicates that the reduction of pollutants from taconite facilities will not result in a discernable visibility improvement in the Class 1 areas.

2.1.3.3 Sources that Already have Effective Emission Control Technology in Place

The 2019 Guidance identified eight example scenarios and described the associated rationale for when sources should be considered "effectively controlled" and that states can exclude similar sources from needing to complete a "four-factor analysis."[35] One of the "effectively controlled" scenarios is for "BART-eligible units that installed and began operating controls to meet BART emission limits for the first implementation period."[36] USEPA caveats this scenario by clarifying that "states may not categorically exclude all BART-eligible sources, or all sources that installed BART control, as candidates for selection for

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[33] Ibid, Page 12.

[34] Ibid, Page 27.

[35] Ibid, Page 22.

[36] Ibid, Page 25.

analysis of control measures."[37] USEPA further notes that "a state might, however, have a different, reasonable basis for not selecting such sources [BART-eligible and non-BART eligible units that implement BART controls] for control measure analysis."[38]

In Section 5, Barr presents an evaluation of the BART-eligible units scenario and demonstrates that the indurating machine is an "effectively controlled" source for both NO_X and SO_2. Thus, a four-factor analysis is not warranted for this source because, as USEPA notes, "it may be unlikely that there will be further available reasonable controls for such sources."[39]

2.2 Facility Description

Minorca mines iron ore (magnetite) and produces taconite pellets that are shipped to steel producers for processing in blast furnaces. The iron ore is crushed and routed through several concentration stages including grinding, magnetic separation, and thickening.

The concentrated iron ore slurry flows to a storage tank where fluxstone is added to make flux pellets. The concentrate is dewatered by vacuum disk filters, mixed with bentonite, and conveyed to balling discs. Greenballs, produced on the balling discs, are transferred to a roll conveyor for additional removal of over-and undersized material.

The greenballs are distributed evenly across pallet cars prior to entering the indurating machine. The pallet cars have a layer of fired pellets, called the hearth layer, on the bottom and sides of the car. The hearth layer acts as a buffer between the pallet car and the heat generated through the exothermic conversion of magnetite to hematite.

Minorca has one natural gas fired indurating machine, with ultra-low sulfur diesel fuel as a back-up for emergency purposes only. Natural gas has been the only fuel combusted at the indurating machine in the last 12 years. The indurating furnace is a straight grate furnace with several distinct zones. The first two stages are updraft and downdraft drying zones. The next zones are the preheat zone and firing zone. The temperature increases as the pellets pass through each zone, reaching a peak in the firing zone. The pellets enter the after-firing zone, where the conversion of magnetite to hematite is completed. The last two zones are cooling zones that allow the pellets to be discharged at a temperature of around 120 degrees Fahrenheit.

Heated air discharged from the two cooling zones is recirculated to the drying, preheat and firing zones. Off-gases from the furnace are vented primarily through two ducts, the hood exhaust that handles the updraft drying and recirculated second cooling gases, and the windbox exhaust, which handles the preheat, firing, after-firing, and downdraft drying gases. The windbox exhaust flows through a multiclone dust collector, which protects the downstream fan, and then enters a common header shared with the hood exhaust stream. The exhaust gases are subsequently divided into four streams, which lead to four

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[37] Ibid.

[38] Ibid.

[39] Ibid.

Taconite Maximum Achievable Control Technology (MACT) venturi rod wet scrubbers that exhaust from individual stacks. Under normal operations, the captured scrubber solids from each of the Taconite MACT four scrubbers are routed back to the concentrate thickener. An overview of the indurating machine design is provided in Figure 2-1.

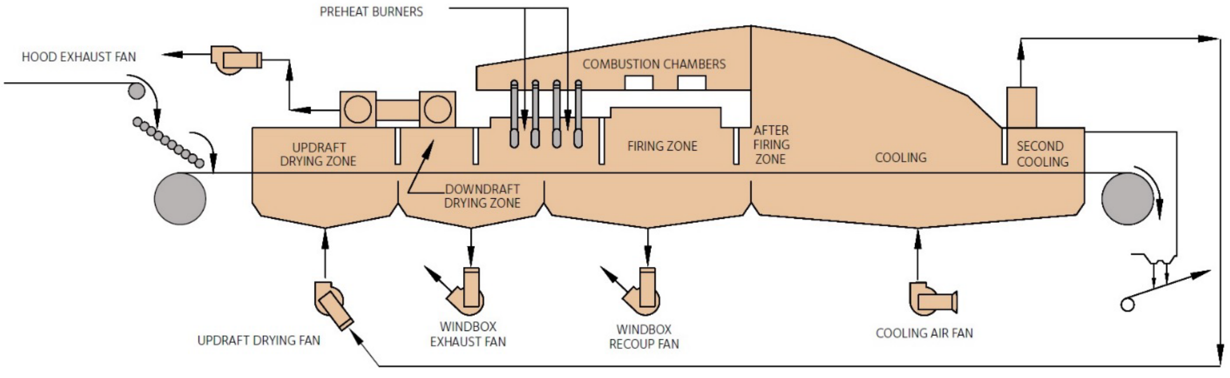

Figure 2-1 Natural Gas Fired Indurating Machine Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT Scrubbers Diagram

3 Analysis of Ambient Data

As described in Section 2.1.2, the SIP must consider visibility conditions (baseline, current, and natural visibility), progress to date, and the URP. This requirement is referred to as Step 1 on the 2019 Guidance (see Section 2.1.3.1). This information informs the State's long term strategy for regional haze, as required by 51.308(f)(2), and the reasonable progress goals, as required by 51.308(3).

Section 3.1 provides analysis of visibility conditions based on data from the IMPROVE monitoring network at BWCA (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1) and Section 3.2 addresses regional emission reductions. Consistent with 51.308(f)(2)(iv), the regional emission reductions summary considers emission reductions that have occurred but are not yet reflected in the available 5-year average monitoring data set and future emission reductions that will occur prior 2028, which is the end of the second SIP implementation period.

3.1 Visibility Conditions

As summarized in Section 2.1.2, the RHR requires that the SIP include an analysis "of baseline, current, and natural visibility conditions; progress to date; and the uniform rate of progress."[40] This data will be used in the SIP to establish reasonable progress goals (expressed in deciviews) that reflect the visibility conditions that are projected to be achieved by the end of the implementation period (2028) as a result of the implementation of the SIP and the implementation of other regulatory requirements.[41] The reasonable progress goal is determined by comparing the baseline visibility conditions to natural visibility conditions and determining the uniform rate of visibility improvement needed to attain natural visibility conditions by 2064. The SIP "must consider the uniform rate of improvement in visibility and the emission-reduction measures needed to achieve it for the period covered by the implementation plan."[42]

MPCA tracks progress towards the natural visibility conditions using data from the IMPROVE visibility monitors at BWCA (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1).[43] The available regional haze monitoring data was compared to the uniform rate of progress and to the possible reasonable progress goals for the SIP for the implementation period, which ends in 2028. As described in Section 2.1.3.1, the visibility metric is based on the 20% most anthropogenically impaired days and the 20% clearest days, with visibility being measured in deciviews (dv). USEPA issued guidance for tracking visibility progress, including the methods for selecting the "most impaired days," on December 20, 2018.[44] Originally, the RHR considered the "haziest days" but USEPA recognized that naturally occurring events (e.g., wildfires and dust storms) could be contributing to visibility and that the "visibility improvements resulting from decreases in anthropogenic emissions can be hidden in this uncontrollable natural variability."[45] In

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[40] 40 CFR 51.308(f)(1)

[41] 40 CFR 51.308(f)(3)

[42] 40 CFR 51.308(d)(1)

[43] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

[44] https://www.epa.gov/visibility/technical-guidance-tracking-visibility-progress-second-implementation-period-regional

[45] USEPA, Federal Register, 05/04/2016, Page 26948

addition, the RHR allows a state to account for international emissions "to avoid any perception that a state should be aiming to compensate for impacts from international anthropogenic sources."[46]

Figure 3-1 through Figure 3-3 show the rolling 5-year average of visibility impairment versus the URP glidepath[47] at BWCA (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1). Regional haze impairment has been declining since 2009 for all three Class I areas that are tracked by MPCA. Impacts to the most impaired days at BWCA and Isle Royale fell below the expected 2028 URP goal in 2016 and have continued trending downward since. Voyageurs impaired days fell below the 2028 URP in 2018 and is also on a downward trend.

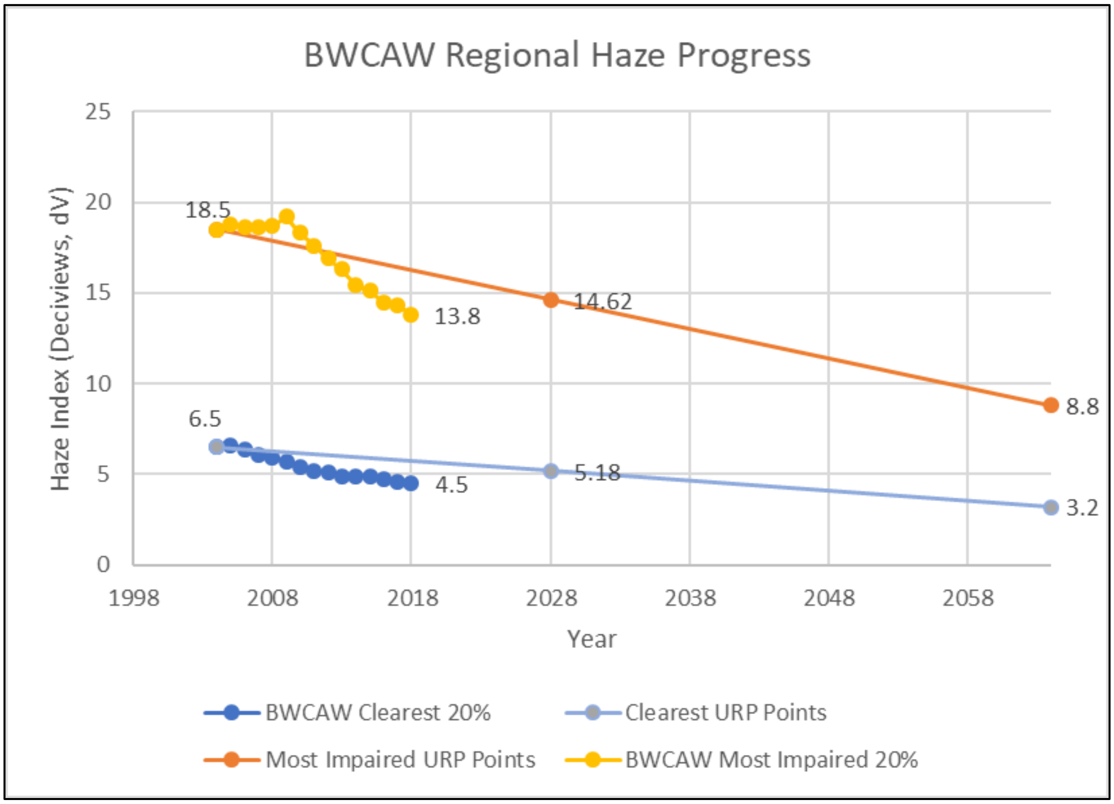

Figure 3-1 Visibility Trend versus URP – Boundary Waters Canoe Area (BOWA1)

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[46] USEPA, Federal Register, 01/10/2017, Page 3104

[47] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

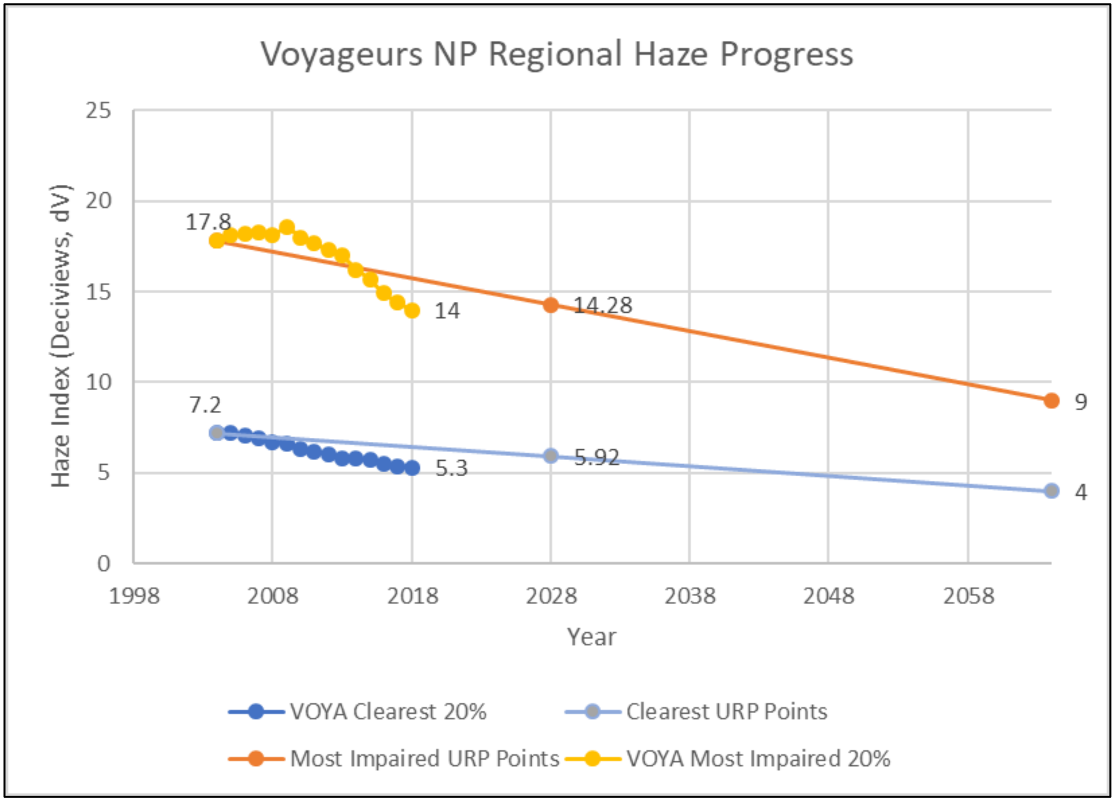

Figure 3-2 Visibility Trend versus URP – Voyageurs National Park (VOYA1)

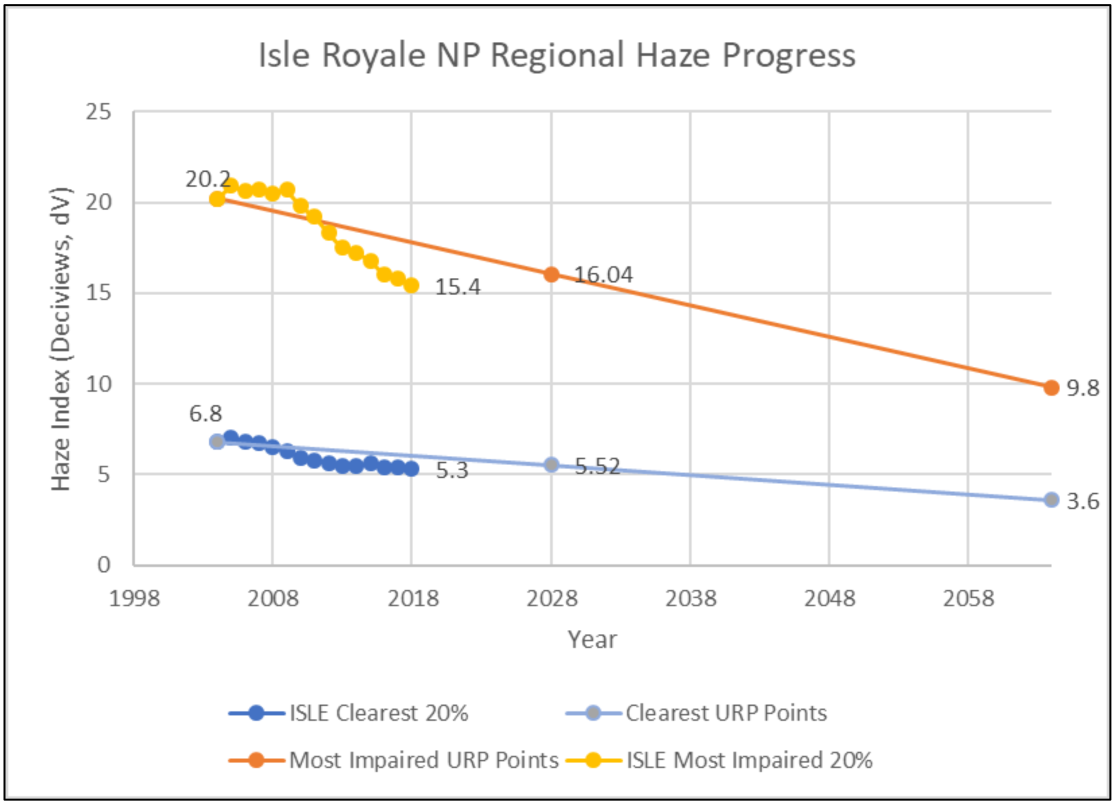

Figure 3-3 Visibility Trend versus URP – Isle Royale National Park (ISLE1)

3.2 Regional emissions reductions

The visibility improvement shown in Figure 3-1 through Figure 3-3 correlates with SO_2 and NO_x emissions decreases from Minnesota's top twenty emission stationary sources, as shown in Figure 3-4[48]. These emission reductions are a result of multiple substantial efforts from the regulated community, including:

- Installation of BART controls during the first implementation period
- Emission reductions at electric utility combustion sources due to new rules and regulations, including:
  - Acid Rain Rules
  - Cross State Air Pollution Rule (CASPR)
  - Mercury and Air Toxics Standards (MATS)
- Electric utility combustion sources undergoing fuel changes (e.g., from coal and to natural gas)
- Increased generation of renewable energy, which decreases reliance on combustion sources

Since many of these emission reduction efforts are due to federal regulations and national trends in electrical generation, similar emission reduction trends are likely occurring in other states.

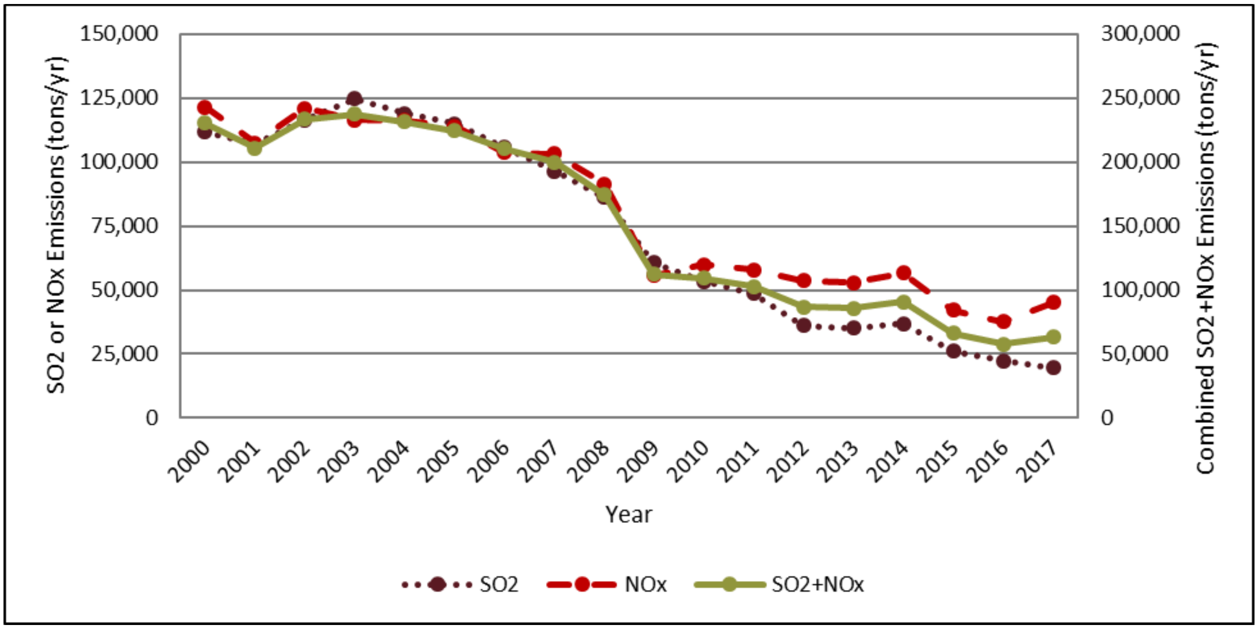

Figure 3-4 Total Emissions of Top-20 Emitters and Taconite Facilities in MN (2000-2017)

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[48] The data for NO_X and SO_2 emissions was downloaded from the MPCA point source emissions inventory (https://www.pca.state.mn.us/air/permitted-facility-air-emissions-data). The permitted facilities that had the 20 highest cumulative emissions from 2000-2017 in MN were chosen for the graphics, along with all six taconite facilities (whether or not they were in the top 20 of the state).

Figure 3-1 through Figure 3-3 show the rolling 5-year average of visibility impairment versus the URP glidepath, so the emissions represented in the most recent data set (2018) is from 2014-2018. However, as shown in Table 3-1, additional emission reductions have occurred since 2014 and are not fully represented in the 5-year visibility data yet. Additionally, several stationary sources have scheduled future emission reductions which will occur prior to 2028. Combined, these current and scheduled emission reductions will further improve visibility in the Class I areas, ensuring the trend stays below the URP. Even without these planned emissions reductions, the 2018 visibility data is already below the 2028 glidepath. As such, MPCA's second SIP implementation period strategy should be commensurate with the region's visibility progress and it would be reasonable for MPCA to not include the taconite indurating furnaces when "reasonably select[ing] a set of sources for an analysis of control measures," and such decision is supported by the 2019 Guidance.

Table 3-1 Notable Minnesota Emission Reductions

Year	Additional Emissions Reductions Expected/Projected
2015	MP Laskin: converted from coal to natural gas**
2017	Minntac Line 6: FIP emission limit compliance date for NO_X*
2018	Minntac Line 7: FIP emission limit compliance date for NO_X* MP Boswell: Units 1 & 2 retired from service**
2019	Hibtac Line 1: FIP emission limit compliance date for NO_X* Keetac: FIP emission limit compliance date for NO_X * Minntac Line 4 or 5: FIP emission limit compliance date for NO_X* Utac Line 1: FIP emission limit compliance date for NO_X*
2020	Hibtac Line 2: FIP emission limit compliance date for NO_X* Minntac Line 4 or 5: FIP emission limit compliance date for NO_X* Minorca: FIP emission limit compliance date for NO_X* Utac Line 2: FIP emission limit compliance date for NO_X*
2021	Minntac Line: FIP emission limit compliance date for NO_X* Hibtac Line 3: FIP emission limit compliance date for NO_X*
2023	Xcel: Sherco Unit 2 Retirement***
2026	Xcel: Sherco Unit 1 Retirement***
2028	Xcel: Allen S. King Plant Retirement***
2030	Xcel: Sherco Unit 3 Retirement, Xcel target to emit 80% less carbon by 2030***
2050	Xcel: Energy targeting carbon free generation by 2050***

* FIP is the regional haze Federal Implementation Plan detailed in 40 CFR 52.1235
** Minnesota Power - Integrated Resource Plan 2015-2029
*** Xcel Energy - Upper Midwest Integrated Resource Plan 2020-2034.

4 Visibility Impacts

As described in Section 2.1.3.2, the 2019 Guidance outlines criteria to evaluate when selecting sources that must complete an analysis of emission controls. The 2019 Guidance is clear that a state does not need to evaluate all sources of emissions but "may reasonably select a set of sources for an analysis of control measures" to make progress towards natural visibility.

As described in Section 2.1.3.2.1, the 2019 Guidance provides recommendations on selecting sources by estimating baseline visibility impacts. Three of the options for estimating baseline visibility impacts are analyzed below:

- *Trajectory analyses*[49]
  In general, these analyses consider the wind direction and the location of the Class I areas to identify which sources tend to emit pollutants upwind of Class I areas. The 2019 Guidance says that a state can consider "back trajectories" which "start at the Class I area and go backwards in time to examine the path that emissions took to get to the Class I areas." Section A1.1 of Appendix A, describes the back trajectory analysis and concludes the taconite indurating furnaces were a marginal contributor to the "most impaired" days from 2009 and 2011-2015. The trajectory analysis also indicates many sources other than the taconite facilities were significant contributors to the "most impaired" days.

- *Photochemical modeling*[50]
  The 2019 Guidance says, "states can also use a photochemical model to quantify source or source sector visibility impacts." CAMx modeling was previously conducted to identify visibility impacts in Class I areas from Minnesota taconite facilities from NOx emission reductions. This analysis is summarized in Section A1.2 of Appendix A which concludes the Class I areas near the Iron Range will not experience any observable visibility improvements from NO_X emission reductions suggested by the USEPA in the final Regional Haze FIP for taconite indurating furnaces.

- *Other reasonable techniques*[51]
  In addition to the two analyses described above which estimate the baseline visibility impacts, Section A1.3 of Appendix A evaluates the actual visibility data against the 2009 economic recession impacts on visibility, when taconite facilities curtailed production. This curtailment resulted in a decrease in emissions from the collective group of taconite plant and the regional power production that is needed to operate the plants. The IMPROVE monitoring data during this curtailment period was compared to monitoring data during more typical production at the taconite plants to estimate the taconite facilities' actual (rather than modeled) impact on haze. This analysis concludes "haze levels in BWCA did not, in general, decrease during 2009, and were therefore unaffected by emission reductions associated with the taconite production slowdown. It

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[49] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, Page 13.

[50] Ibid, Page 14.

[51] Ibid, Page 12.

is noteworthy that peak events during mid-2009 in sulfate haze at BWCA when very little taconite production was occurring clearly indicate that minimal haze reduction would likely be associated with taconite plant emission reductions."[52] The report further notes "high nitrate haze days late in 2009 with the taconite plant curtailment that are comparable in magnitude to full taconite production periods in 2008. We also note that after the taconite plants went back to full production in 2010, the haze levels dropped, apparently due to emissions from other sources and/or states."[53]

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[52] AECOM, "Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas," 09/28/2012, Page 10.

[53] Ibid, Page 12.

5 Evaluation of “Effectively Controlled” Source

As described in Section 2.1.3.3, the 2019 Guidance acknowledges that states may forgo requiring facilities to complete the detailed four-factor analysis if the source already has “effective emission control technology in place.”[54] This section demonstrates that the indurating machine meets USEPA’s BART-required control equipment installation scenario for NO_X and SO_2.

The indurating machine meets this scenario as an “effectively controlled source” because:

- The indurating machine is a BART-eligible unit, as determined by Minnesota’s December 2009 Regional Haze Plan, and is regulated under 40 CFR 52.1235 (Approval and Promulgation of Implementation Plans – Subpart Y Minnesota – Regional Haze)
- The indurating machine has controls and must “meet BART emission limits for the first implementation period”[55] for NO_X and SO_2

The following sections describe USEPA’s BART determinations, the associated controls that were implemented as BART, and the resulting BART emission limits for NO_X and SO_2.

5.1 NO_X BART-required Controls

In the preamble to the October 2015 proposed FIP,[56] the USEPA concluded that BART for NO_X from straight-grate furnaces is low-NO_X burners with water/steam injection and pre-combustion technologies. As part of the evaluation, USEPA eliminated the following emission control measures because they were technically infeasible:

- External and Induced Flue Gas Recirculation Burners due to the high oxygen content of the flue gas[57]
- Energy Efficiency Projects due to the difficulty with assigning a general potential emission reduction for this emission control measure[58]
- Selective Catalytic Reduction (SCR) controls because two vendors declined to bid on NO_x reduction testing for a taconite facility[59]

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[54] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, page 22.

[55] Ibid, page 25.

[56] Federal Register 80, No. 204 (October 22, 2015); 64168. Available at: https://www.govinfo.gov/app/details/FR-2015-10-22/2015-25023

[57] Federal Register 77, No. 158 (August 15, 2012); 49319. Available at: https://www.govinfo.gov/app/details/FR-2012-08-15/2012-19789

[58] Ibid.

[59] Ibid, 49320.

- High-stoichiometric and low-stoichiometric low NO_x burners (LNB) because the technology had never been used on straight-grate furnaces at the time of the determination.[60]

Because the technical feasibility determinations of the listed control measures have not materially changed since the 2016 final FIP, there are no "further available reasonable controls" for NO_X emissions from taconite indurating furnaces.

In accordance with the FIP, Minorca implemented the BART NO_x control measures by installing and operating newly engineered site-specific Low NOx Burner technology prior to the required FIP compliance date of January 12, 2020 and the indurating machine is subject to the FIP NO_x emission limit[61] as shown in Table 5-1. The indurating furnace Low NOx Burners have reduced the majority of the NOx emissions. Thus, the indurating machine is considered an "effectively controlled source" in accordance with the 2019 Guidance and should be excluded from the requirement to prepare and submit a four-factor analysis. In addition, the BART analysis, which was finalized in 2016, already addressed the elements of the four-factor analysis, which further supports eliminating the indurating machine from the requirement to submit a four-factor analysis[62].

Table 5-1 NO_X Emission Limits

Unit	Unit ID	NO_X Emission Limit(1) (lb/MMBtu)	Compliance Date(2)
Natural Gas Fired Indurating Machine Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT Scrubbers	(EQUI 38/EU 026)	1.2-1.8	December 12, 2020

(1) In accordance with 40 CFR 52.1235(b)(1)(v)(A), EQUI 38/EU 026 will be limited to 1.2 to 1.8 lb NOx/MMBtu/hr beginning December 12, 2020. The specific emission limit will be established by USEPA based on available NOx CEMS data from the time period when the installed emission control technology was in operation and must be submitted by September 12, 2020.

(2) The compliance date is contingent on USEPA's approval of the final emission limit.

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[60] Federal Register 80, No. 204 (October 22, 2015); 64167. Available at: https://www.govinfo.gov/app/details/FR-2015-10-22/2015-25023

[61] 40 CFR 52.1235(b)(1)

[62] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, Page 10.

5.2 SO_2 BART-required Controls

In the preamble to the August 2012 proposed FIP[63], the USEPA concluded that BART for SO_2 emissions from the indurating machine at Minorca is existing controls. As part of the evaluation, USEPA eliminated the following emission control measures because they were technically infeasible:

- Dry Sorbent Injection and Spray Dryer Absorption because the high moisture content of the exhaust would lead to baghouse filter cake saturation and filter plugging
- Alternative Fuels due to Minorca being prohibited from burning solid fuel
- Coal drying/processing because the indurating machine uses natural gas
- Energy Efficiency Projects due to the difficulty with assigning a general potential emission reduction for this emission control measure[64]
- Caustic, lime, or limestone additives to existing scrubbers operating to increase the pH of the scrubbing liquid due to corrosion concerns of the control system that were not designed to operate at a higher pH. The preamble also cited concerns with additional solids and sulfates that would be discharged to the tailing basin and would require extensive treatment to maintain water quality and/or would cause an increased blowdown and make-up water rate, which is not available[65]

In addition, USEPA eliminated Wet Walled Electrostatic Precipitator (WWESP) and secondary (polishing) wet scrubber technologies because they were not cost-effective.[66]

Because the technical feasibility and cost effectiveness determinations of the listed control measures have not materially changed since the 2016 final FIP, there are no "further available reasonable controls" for SO_2 emissions from taconite indurating furnaces.

In accordance with the FIP, Minorca has continued to operate the BART SO_2 control measures and is complying with the FIP SO_2 emission limit[67], as shown in Table 5-2. Thus, the indurating machine is considered an "effectively controlled source" in accordance with the 2019 Guidance and can reasonably be excluded from the requirement to prepare and submit a four-factor analysis for SO_2. In addition, the BART analysis, which was finalized in 2016, already addressed the elements of the four-factor analysis,

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[63] Federal Register 77, No. 158 (August 15, 2012); 49321. Available at: https://www.govinfo.gov/app/details/FR-2012-08-15/2012-19789

[64] Ibid, 49320.

[65] Ibid.

[66] Ibid, 49321.

[67] 40 CFR 52.1235(b)(2)

which further supports eliminating the indurating machine from the requirement to submit a four-factor analysis[68].

Table 5-2 SO_2 Emission Limits

Unit	Unit ID	SO_2 Emission Limit(1) (lb/hr)	Compliance Date(2)
Natural Gas Fired Indurating Machine Equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT Scrubbers	(EQUI 38/EU 026)	58.64	April 6, 2018

(1) This limit was established using one year of SO_2 CEMS data in accordance with the procedures outlined within 40 CFR 52.1235(b)(2)(v).

(2) Minorca submitted the revised SO_2 limit request on April 6, 2018 in accordance with 40 CFR 52.1235(b)(2)(v).

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[68] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, Page 10.

6 Conclusion

The preceding sections of this report support the following conclusions:

- The natural gas fired indurating machine equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT scrubbers meets the BART-required control equipment installation scenario and is an "effectively controlled" source for NO_X and SO_2 (see Section 5). As stated in the 2019 Guidance, "it may be reasonable for a state not to select an effectively controlled source."[69] Therefore, it would be reasonable and compliant with USEPA requirements to exclude Minorca from further assessments of additional emission control measures.

- There has been significant progress on visibility improvement in the nearby Class I areas and MPCA's reasonable progress goals should be commensurate with this progress (see Section 3):

    - Visibility has improved at all three monitors (BOWA1, VOYA2, and ISLE1) compared to the baseline period

    - Visibility has been below the URP since 2012

    - The 2018 visibility data is below the URP for 2028

    - Additional emissions reductions have continued throughout the region and are not fully reflected in the available 5-year average (2014-2018) monitoring dataset

    - Additional emission reductions are scheduled to occur in the region prior to 2028, including ongoing transitions of area EGUs from coal to natural gas or renewable sources, as well as the installation of low-NO_X burners throughout the taconite industry

- The indurating machine does not materially impact visibility from a theoretical (modeling) and empirical (actual visibility data) basis and should not be required to assess additional emission control measures. (see Section 4).

The combination of these factors provides sufficient justification for MPCA to justify to USEPA Minorca's exclusion from the group of sources required to conduct a four-factor analysis for this implementation period. **Thus, Minorca respectfully requests that the MPCA timely withdraw its request for a four-factor analysis for the natural gas fired indurating machine already equipped with Newly Engineered Site-Specific Low NOx Burner Technology and Taconite MACT scrubbers.**

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[69] Ibid, Page 22

Appendix

Appendix A

Visibility Impacts

A1 Visibility Impacts

A1.1 Trajectory Analysis

The August 2019 U.S. EPA Guidance ("2019 Guidance" or "the Guidance")[1] says that the state may use a "reasonable surrogate metrics of visibility impacts" when selecting sources to conduct an four-factor analysis and cites trajectory analysis as an example of a reasonable technique. This analysis considers reverse trajectories, as provided on MPCA's website[2], to determine the frequency that the trajectories on the "most impaired days"[3] overlapped with a specific area of influence (AOI) on the Iron Range. Data from 2011-2015 were analyzed as this was the most recent five-year period where the taconite facilities were operating under typical production rates.

A particle trajectory analysis is an analysis of the transport path of a particular air mass, including the associated particles within the air mass, to see if the air mass traveled over certain locations from specific source locations. The MPCA tracks visibility via the IMPROVE (Interagency Monitoring of Protected Visual Environments) monitoring sites at Boundary Waters Canoe Area Wilderness (BWCA), Voyageurs National Park (Voyageurs) and Isle Royale National Park (Isle Royale).[4] MPCA's website includes a tool which analyzes reverse trajectories from BWCA and Voyageurs for the "most impaired days" and the clearest days for 2007-2016 to show the regional influence on visibility. The reverse trajectories included in the MPCA tool were developed using the NOAA Hysplit model.[5] The trajectories consist of a single back trajectory for each day of interest, beginning at 18:00 and running back 48 hours with a starting height of 10 meters.

The MPCA Hysplit reverse trajectories from the "most impaired days" were analyzed to identify whether trajectories overlapped with an AOI from certain taconite facilities on the Iron Range. In order to be conservative, Barr estimated an "uncertainty region" for each trajectory based on 20% of the distance traveled for every 10km along the trajectory pathway. This method is consistent with other scientific studies analyzing reverse trajectories and trajectories associated with the NOAA Hysplit model (Stohl - 1998[6], Draxler - 1992[7], Draxler and Hess - 1998[8]). For the purpose of this analysis, the Iron Range AOI was defined as a line connecting the stack at the U. S. Steel Keetac facility with the stack at the ArcelorMittal Minorca Mine and a 3-mile radius surrounding the line. This analysis considers how often the MPCA reverse trajectories overlap the Iron Range AOI on the "most impaired days" to quantitatively determine if the emissions from the Iron Range may have been a contributor to impaired visibility. Attachment 1 to Appendix A includes tables with the annual and seasonal results of this analysis as well as two example figures showing trajectories that cross, and do not cross, the Iron Range AOI.

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[1] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[2] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Regionalinfluence

[3] "Most impaired days" is the 20% most anthropogenically impaired days on an annual basis, measured in deciviews (dv), as provided on MPCA's website.

[4] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Regionalinfluence

[5] https://www.arl.noaa.gov/hysplit/hysplit/

[6] http://www.kenrahn.com/DustClub/Articles/Stohl%201998%20Trajectories.pdf

[7] https://www.arl.noaa.gov/documents/reports/ARL%20TM-195.pdf

[8] https://www.arl.noaa.gov/documents/reports/MetMag.pdf

As shown in Figure A1 and Figure A2, reverse trajectories from BWCA and Voyageurs in 2011-2015 did not overlap the Iron Range AOI on 62-80%, and 56-71% of “most impaired days”, respectively. This means the taconite industry did not influence visibility at BWCA and Voyageurs on the majority of “most impaired days” and suggest that sources other than the taconite facilities are larger contributors to visibility impairment at these sites. Furthermore, the origins of many of the “most impaired day” reverse trajectories are beyond the Iron Range AOI and thus have influences, depending on the trajectory, from other sources (e.g., Boswell Energy Center, Sherburne County Generating Station) or cities such as Duluth, St. Cloud, the Twin Cities, and Rochester as shown in Figure A3.

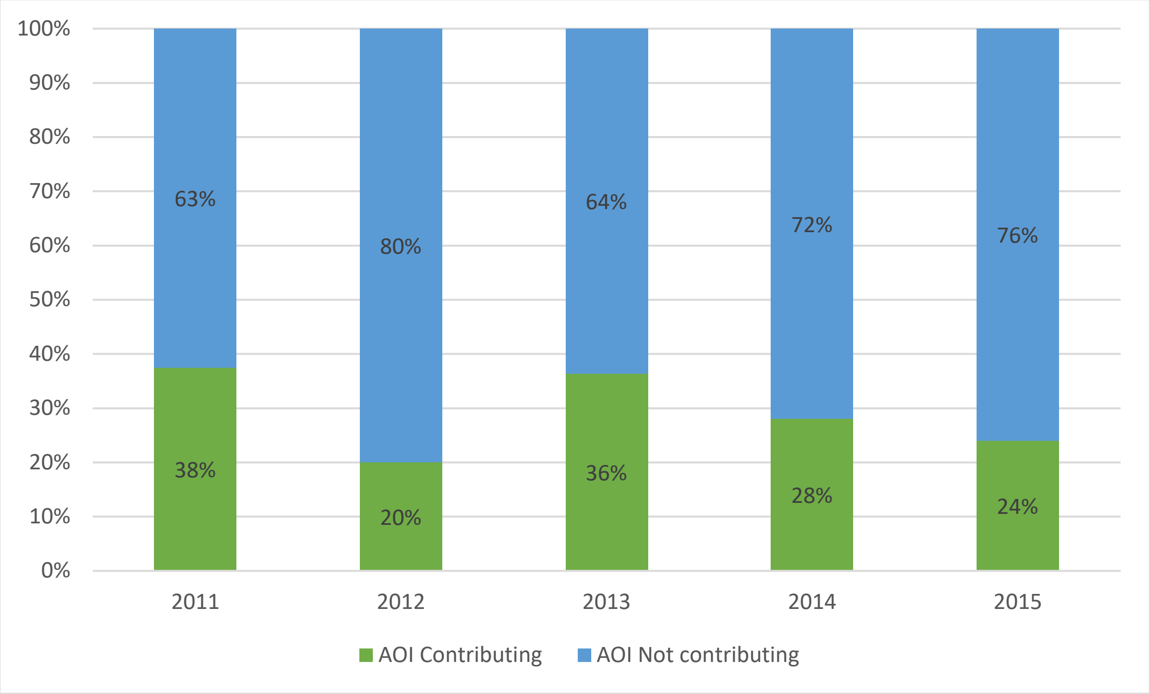

Figure A1 Proportion of “most impaired days” Iron Range AOI was Contributing or Not Contributing to Visibility at BWCA

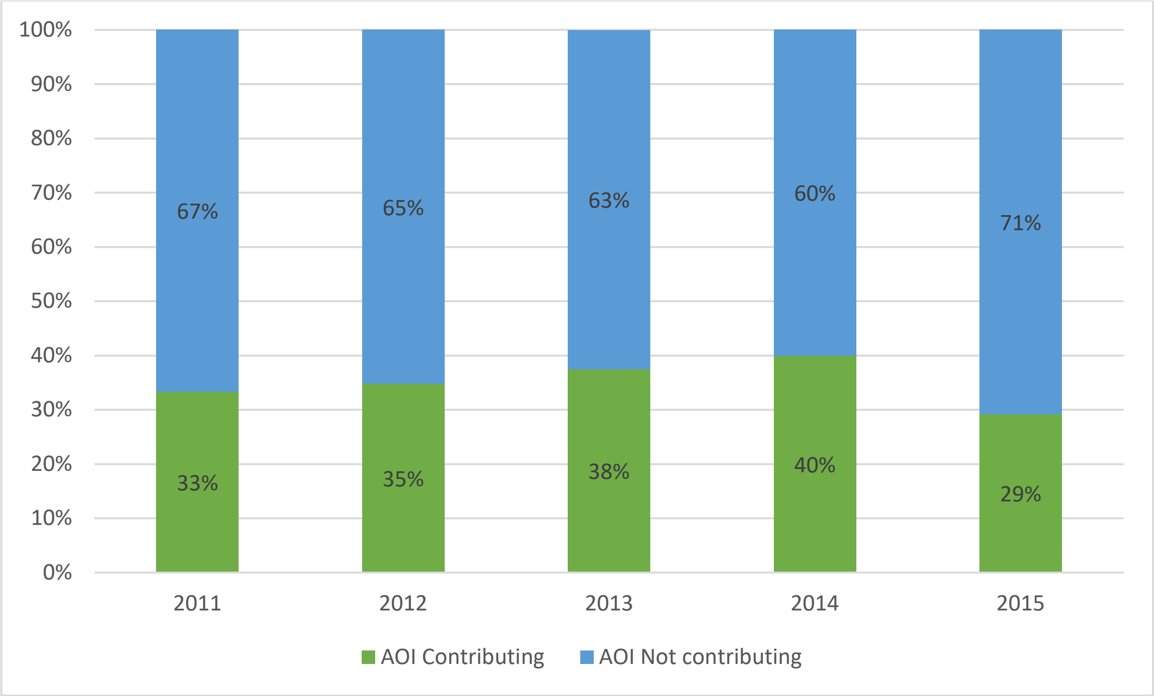

Figure A2 Proportion of "most impaired days" Iron Range AOI was Contributing or Not Contributing to Visibility at Voyageurs

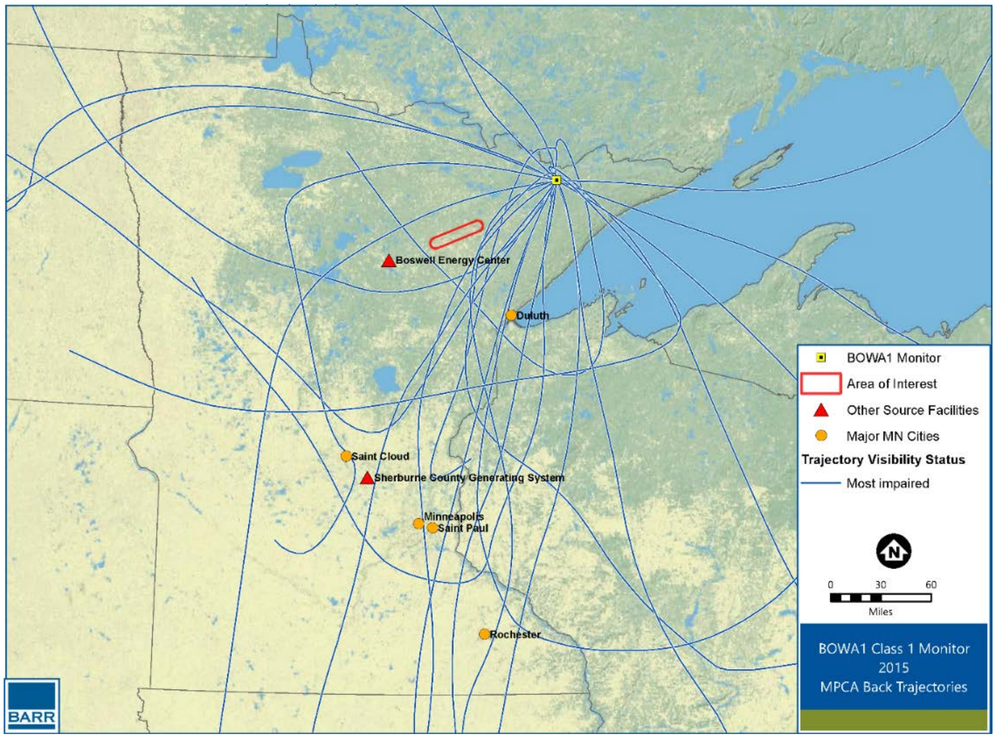

Figure A3 Reverse Trajectories and Other Sources Influencing Visibility at BWCA[9]

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[9] Source: ArcGIS 10.7.1, 2020-05-14 13:31 File: I:\Client\US_Steel\Trajectory_Analysis\Maps\Trajectory_Routes_BOWA1_2015_zoom.mxd User: ADS

A1.2 Photochemical Modeling

As part of the requirement to determine the sources to include and how to determine the potential visibility improvements to consider as part of this selection, the 2019 Guidance provided some specific guidance on the use of current and previous photochemical modeling analyses (emphasis added):

> *"A state opting to select a set of sources to analyze must reasonably choose factors and apply them in a reasonable way given the statutory requirement to make reasonable progress toward natural visibility. Factors could include but are not limited to baseline source emissions, baseline source visibility impacts (or a surrogate metric for the impacts), [and] the in-place emission control measures…"*[10]

The Guidance lists options for the evaluation of source visibility impacts from least rigorous to most rigorous as: (1) emissions divided by distance (Q/d), (2) trajectory analyses, (3) residence time analyses, and (4) photochemical modeling (zero-out and/or source apportionment). It appears that MPCA selected the least rigorous (Q/d) for inclusion of sources in the four-factor analyses. The most rigorous is described below (emphases added):

> ***"Photochemical modeling****. In addition to these non-modeling techniques, states can also use a photochemical model to quantify source or source sector visibility impacts. In 2017, EPA finalized revisions to 40 CFR Part 51 Appendix W, Guideline on Air Quality Models. As part of that action, EPA stated that photochemical grid models should be the generally preferred approach for estimating source impacts on secondary PM concentrations. The existing SIP Modeling Guidance provides recommendations on model setup, including selecting air quality models, meteorological modeling, episode selection, the size of the modeling domain, the grid size and number of vertical layers, and evaluating model performance. EPA Regional offices are available to provide an informal review of a modeling protocol before a state or multijurisdictional organization begins the modeling.*
>
> *The SIP Modeling Guidance focuses on the process for calculating RPGs using a photochemical grid model. The SIP Modeling Guidance does not specifically discuss using photochemical modeling outputs for estimating daily light extinction impacts for a single source or source sector. However, the approach on which the SIP Modeling Guidance is based can also be applied to a specific source or set of sources. The first step in doing this is to estimate the impact of the source or set of sources on daily concentrations of PM species.*
>
> *The simplest approach to quantifying daily PM species impacts with a photochemical grid model is to perform brute force "zero-out" model runs, which involves at least two model runs: one "baseline" run with all emissions and one run with emissions of the source(s) of interest removed from the baseline simulation. The difference between these simulations provides an estimate of the PM species impact of the emissions from the source(s).*

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[10] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, Page 10

> *An alternative approach to quantifying daily PM species impacts is photochemical source apportionment. Some photochemical models have been developed with a photochemical source apportionment capability, which tracks emissions from specific sources or groups of sources and/or source regions through chemical transformation, transport, and deposition processes to estimate the apportionment of predicted $PM_{2.5}$ species concentrations. Source apportionment can "tag" and track emissions sources by any combination of region and sector, or by individual source. For example, PM species impacts can be tracked from any particular source category in the U.S., or from individual states or counties. Individual point sources can also be tracked."*[11]

As part of the previous regional haze planning evaluation, and to provide comments on USEPA's disapproval of the Minnesota SIP and the subsequent Regional Haze Federal Implementation Plan (FIP) (Docket EPA-R05-OAR-2010-0954 & EPA-R05-OAR-2010-0037), Barr completed photochemical modeling of ArcelorMittal and Cleveland-Cliffs' taconite operations in 2013 using CAMx source apportionment (see Attachment 2). The basis of the CAMx modeling was the Minnesota modeling analyses, which were completed as part of the regional haze SIP, including Plume in Grid (PiG) evaluations of sources included in BART analyses. This modeling included 2002 and 2005 baseline periods with projected emissions to 2018 (the first implementation planning period for the regional haze SIPs and a strong surrogate for the baseline period for the 2nd planning period). Therefore, the analysis completed is one of the best available surrogates for the potential visibility impacts from the sources that were "tagged" as part of those comments. It is important to note that the MPCA modeling analysis did not require any additional controls for taconite sources under BART. Further, the CAMx modeling that Barr conducted showed that the impact from NO_X emissions from the Minnesota taconite facilities had very limited visibility impacts on the three Upper Midwest Class I areas.

Specifically, the results from executing CAMx concluded that the Class I areas near the Iron Range will not experience any observable visibility improvements from NO_X emission reductions that were suggested by the USEPA in the final Regional Haze FIP for taconite indurating furnaces. The modeling analysis showed that the scalar method that USEPA used to forecast the visibility improvements was inadequate to determine the visibility impacts from taconite sources. The CAMx predicted impacts for every furnace line were at or below the de minimis threshold for visibility improvement (0.1 delta-dV).

In addition, the large amount of potential NO_X emission reductions from the FIP baseline to the final FIP (>10,000 tons per year from modeled Minnesota taconite operations) was not impactful from a visibility modeling perspective. This finding provides specific source modeling evidence that additional NOx emission reductions from any or all of the taconite operations are likely not helpful for visibility improvements at the Upper Midwest Class I areas. This is particularly true given the current amount of NO_X emissions generated by the taconite sources as part of the current baseline.

The 2019 Guidance addresses how states should select sources that must conduct a four-factor analysis. The RHR suggests that states can use a photochemical model to quantify facility or even stack visibility impacts. The previous CAMx modeling was conducted for the 2018 projection year and the results are

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[11] Ibid, Page 14.

especially helpful in the current visibility impact assessment to determine if the EPA's four-factor applicability analysis is necessary. Aside from the fact that the NO_X reductions of taconite indurating furnaces do not result in visibility improvements, the emissions from these sources have been trending downward from 2013 to present. These reductions are related to the recent installation of low NO_X burners on the taconite indurating furnaces and the overall Minnesota state reductions from the switch from coal- to natural gas-fired power plants. Thus, it is reasonable to conclude that additional emission reductions beyond the FIP limits of the taconite indurating furnaces will not be beneficial to improve visibility at the Class 1 areas nor is it anticipated to be necessary to reach the 2028 target visibility goal.

In summary, the exclusion of the taconite sources from the four factor analysis for NOx is reasonable, supported by the previous CAMx modeling performed for 2018 projected emissions that conclude additional emission reductions beyond the FIP limits of the taconite indurating furnaces will not be beneficial to improve visibility, and in line with the Guidance regarding selection of sources based on previous modeling analyses and the additional NO_X reductions anticipated in Minnesota.

A1.3 Visibility Impacts During 2009 Recession

During the economic recession in 2009, the Iron Range experienced a reduction in taconite production. This resulted in a decrease in emissions from the collective group of taconite plants and the regional power production that is needed to operate the plants. The IMPROVE monitoring data during this period was compared to monitoring data during more typical production at the taconite plants to estimate the actual (rather than modeled) impact on haze. This assessment was completed in 2012 (herein termed as "the 2012 analysis") and submitted by Cliffs as a comment to proposed Minnesota regional haze requirements (Docket: EPA-R05-OAR-2010-0037), included as Attachment 3. The 2012 analysis focused on the likely visibility impact of NO_X emissions from the taconite indurating furnaces.

Observations noted in the 2012 analysis highlighted that concentrations of visibility impairing pollutants do not appear to closely track with actual emissions from taconite facilities. For example, nitrate (NO_3) is a component of haze associated with NO_X emissions that are emitted from a number of sources, including the indurating furnaces at the taconite facilities. As shown in Figure A4, the 2012 analysis compared taconite facility production rates to nitrate concentration for 1994-2010 at the BWCA monitor. The 2012 analysis concludes that "haze levels in BWCA did not, in general, decrease during 2009, and were therefore unaffected by emission reductions associated with the taconite production slowdown. It is noteworthy that peak events during mid-2009 in sulfate haze at BWCA when very little taconite production was occurring clearly indicate that minimal haze reduction would likely be associated with taconite plant emission reductions."[12] The report further notes that "high nitrate haze days late in 2009 with the taconite plant curtailment that are comparable in magnitude to full taconite production periods in 2008. We also note that after the taconite plants went back to full production in 2010, the haze levels dropped, apparently due to emissions from other sources and/or states."[13]

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[12] AECOM, "Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas," 09/28/2012, Page 10.

[13] Ibid, Page 12.

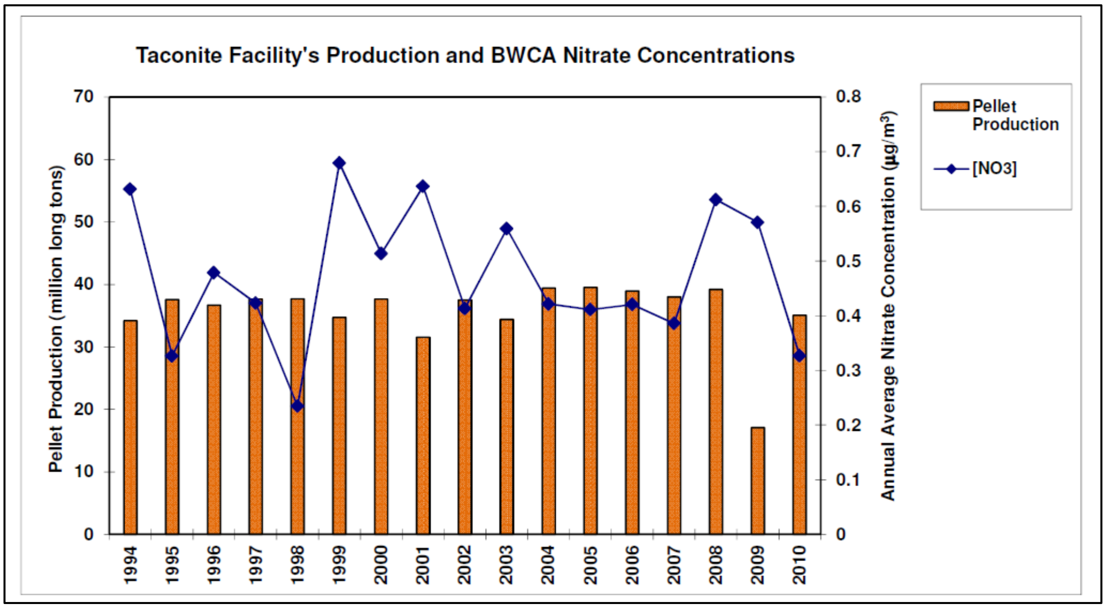

Figure A4 Minnesota Taconite Production and BWCA Nitrate Concentrations 1994-2010 [14]

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[14] AECOM, "Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas," 09/28/2012, Page 9

Attachments

Attachment 1

Trajectory Analysis Summary Tables and Reverse Trajectory Example Figures

Table A1 Results from MPCA Hysplit Trajectories for the BOWA1 Monitor

Year	Time Period	Most Impaired Days	"Most Impaired" Trajectories With Uncertainty Region Crossing Iron Range AOI (%)
2011	Winter (DJF)	9	44%
	Spring (MAM)	8	38%
	Summer (JJA)	4	0%
	Fall (SON)	3	67%
	Total	**24**	**38%**
2012	Winter (DJF)	13	23%
	Spring (MAM)	4	0%
	Summer (JJA)	1	0%
	Fall (SON)	7	29%
	Total	**25**	**20%**
2013	Winter (DJF)	9	44%
	Spring (MAM)	5	60%
	Summer (JJA)	3	0%
	Fall (SON)	5	20%
	Total	**22**	**36%**
2014	Winter (DJF)	9	33%
	Spring (MAM)	8	13%
	Summer (JJA)	2	0%
	Fall (SON)	6	50%
	Total	**25**	**28%**
2015	Winter (DJF)	13	15%
	Spring (MAM)	3	67%
	Summer (JJA)	1	0%
	Fall (SON)	8	25%
	Total	**25**	**24%**

Table A2 Results from MPCA Hysplit Trajectories for the VOYA2 Monitor

Year	Months	Most Impaired Days	"Most Impaired" Trajectories With Uncertainty Region Crossing Iron Range AOI (%)
2011	Winter (DJF)	8	38%
	Spring (MAM)	7	29%
	Summer (JJA)	4	25%
	Fall (SON)	5	40%
	Total	**24**	**33%**
2012	Winter (DJF)	13	23%
	Spring (MAM)	3	67%
	Summer (JJA)	0	0%
	Fall (SON)	7	43%
	Total	**23**	**35%**
2013	Winter (DJF)	9	22%
	Spring (MAM)	5	40%
	Summer (JJA)	3	0%
	Fall (SON)	7	71%
	Total	**24**	**38%**
2014	Winter (DJF)	10	50%
	Spring (MAM)	7	43%
	Summer (JJA)	2	0%
	Fall (SON)	6	33%
	Total	**25**	**40%**
2015	Winter (DJF)	14	21%
	Spring (MAM)	4	50%
	Summer (JJA)	1	100%
	Fall (SON)	5	20%
	Total	**24**	**29%**

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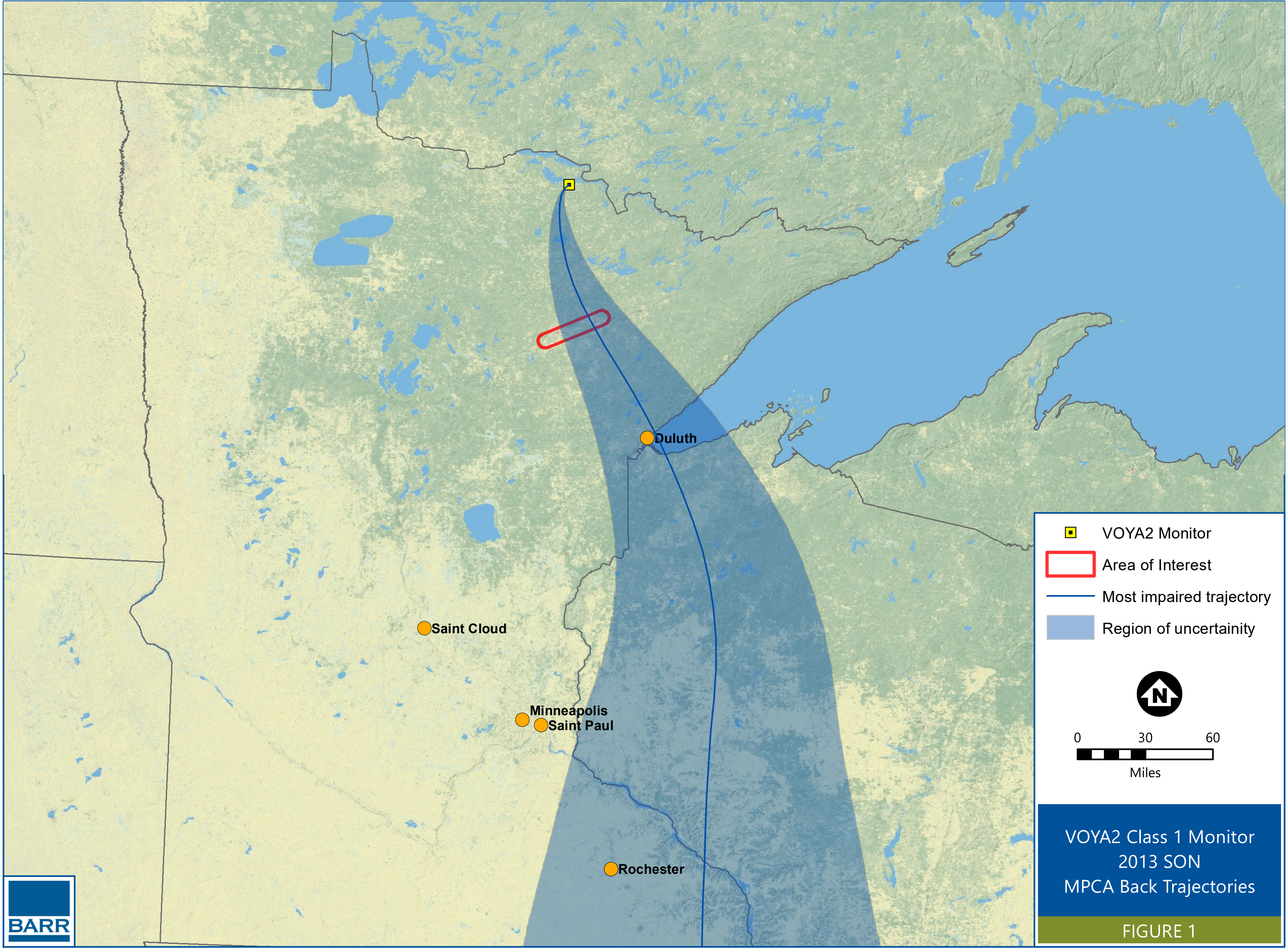

VOYA2 Class 1 Monitor
2013 SON
MPCA Back Trajectories

FIGURE 1

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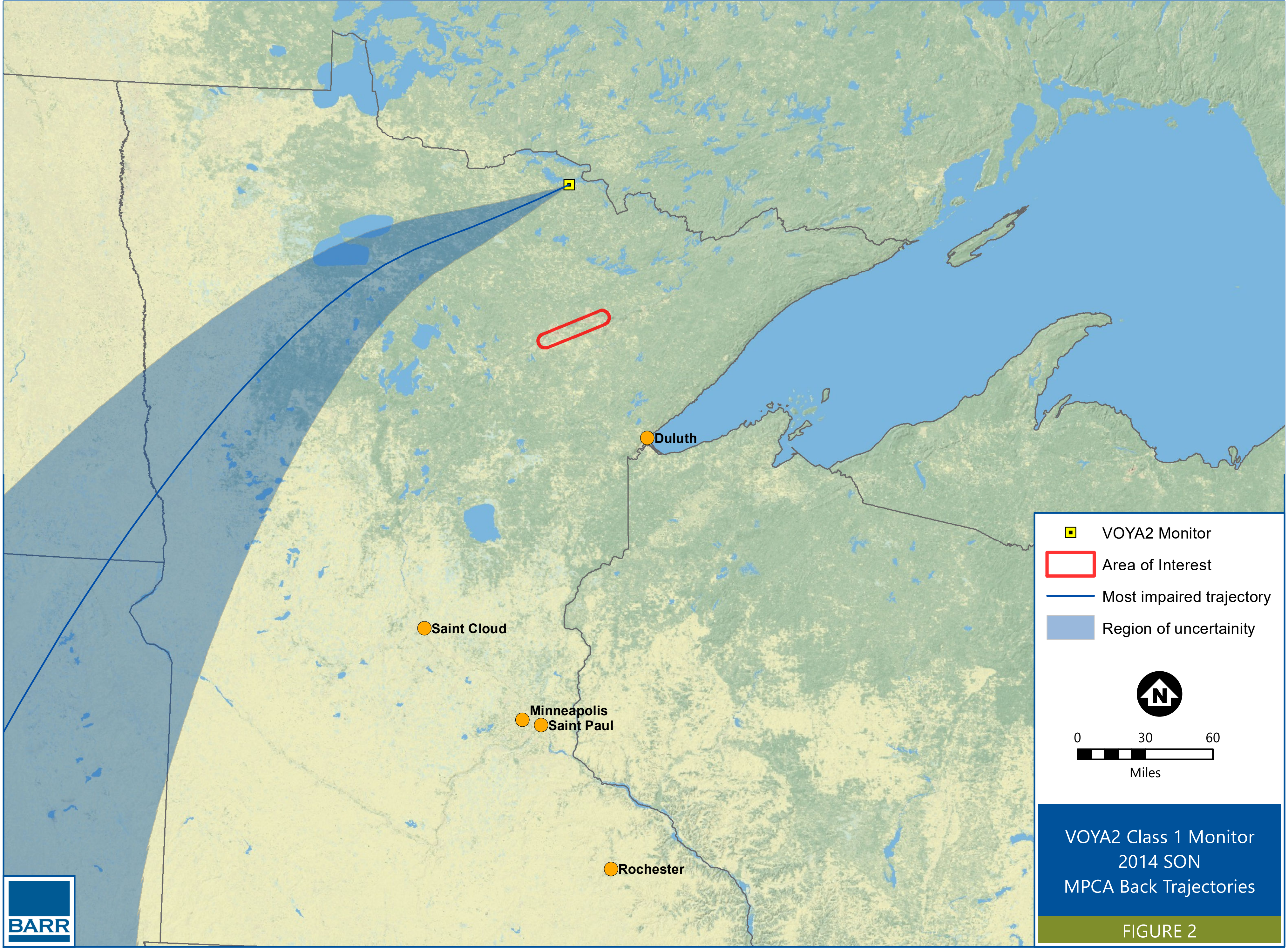

VOYA2 Class 1 Monitor
2014 SON
MPCA Back Trajectories

FIGURE 2

Attachment 2

CAM$_X$ Modeling Report

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Technical Memorandum

From: Barr Engineering
Subject: Summary of Comprehensive Air Quality Model with Extensions (CAM_X) Analyses Performed to Evaluate the EPA Regional Haze Federal Implementation Plan for Taconite Facilities
Date: March 6, 2013

Executive Summary

Barr Engineering conducted air modeling to predict the impact of NO_X reductions from certain taconite furnaces in Minnesota and Michigan. Using EPA's preferred Comprehensive Air Quality Model with Extensions (CAM_X), the model results demonstrate that the Class I areas near these furnaces will experience no perceptible visibility improvements from NO_X emission reductions envisioned by EPA in the recent Regional Haze FIP at the furnaces. The analysis strongly suggests that the scalar method that EPA used to predict visibility improvements under significant time constraints was an inadequate substitute for CAM_X, as EPA's approach over-predicted visibility impacts by factors of ten to sixty when compared with the proper CAM_X analysis. The basis for EPA's technical analysis of the visibility improvements for their proposed emission changes must therefore be dismissed as unsupportable, and the results of this analysis should be used instead. This analysis ultimately supports the conclusions of the States of Michigan and Minnesota in their Regional Haze SIPs, that experimental low NO_X burner retrofits did not meet the criteria for BART. The imperceptible visibility improvements associated with NO_X reductions from these furnaces cannot justify the cost or the operational risks of changing burners.

Discussion

This memorandum provides a summary of the methodology and results from photochemical modeling analyses conducted to support the Cliffs Natural Resources (CNR) and Arcelor Mittal (Arcelor) response to the United States Environmental Protection Agency (EPA) final Regional Haze Federal Implementation Plan (FIP) for taconite facilities. Further, it provides a basis for comment on the proposed disapproval of the Minnesota and Michigan State Implementation Plans for taconite Best Available Retrofit Technology (BART) at the above mentioned facilities. This memorandum also includes an appendix with a summary of the BART visibility improvement requirements and a review of

the EPA "scalar" method in the proposed and final FIP for determining the visibility improvement from taconite emission reductions. Further, the memorandum contrasts EPA's findings with the modeling analysis conducted and previously requested by CNR as part of its comments on the proposed FIP. The modeling evaluated emission differences at all the CNR and Arcelor taconite facilities.

Ultimately, this memorandum provides results demonstrating no perceptible visibility improvement from the NO_X emission reductions proposed and subsequently finalized by EPA in the Regional Haze FIP for the CNR and Arcelor facilities.

I. CAM_X Modeling Methodology

The methodology utilized by Barr to complete the CAM_X modeling was identical to the methods utilized by the Minnesota Pollution Control Agency (MPCA) in performing the 2002 and 2005 baseline and BART SIP modeling in 2009. This included the use of the CAM_X modeling system (CAM_X v5.01 - air quality model, MM5 - meteorological model, and EMS-2003 - emissions model) with meteorological data, low-level emission data, initial and boundary condition files, and other input files received directly from MPCA. Modifications to the emissions within the elevated point source input files used by MPCA were accomplished for the taconite facility furnace stacks to reflect the differences in the FIP baseline and final FIP control scenarios. In addition, the CAM_X run scripts used to execute the model were provided by MPCA for each of the four calendar quarters (Jan-Mar, Apr-Jun, Jul-Sep, and Oct-Dec) along with the post-processing scripts used to estimate the visibility impacts for each scenario.

An important fact is that the results from the MPCA modeling for Minnesota's regional haze State Implementation Plan (SIP) development were also utilized by EPA in the "scalar" method proposed in the FIP. These results were subsequently defended by EPA in the final FIP stating "EPA stands by the results of its ratio approach and believes that it produced reasonable results for the sources examined."[1] The methods utilized by MPCA represent not only an EPA-approved approach for SIP submittal, but also formed the basis of the visibility determinations made by EPA in the proposed and final FIP. However, since EPA did not conduct its own modeling and provided only the "scalar" results, there are substantial and inherent flaws in the EPA-estimated visibility impacts. These flaws are detailed in Appendix A to this memorandum which includes a review of the EPA scalar approach. Since the modeling reported here used identical methods to the MPCA analyses, it is consistent with the underlying data that was used in

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[1] Federal Register, Volume 78, Number 25, page 8721, February 6, 2013

the EPA FIP method for estimating visibility impact. Further, this modeling provides specific technical analyses regarding the estimated effects of CNR and Arcelor taconite unit emission reductions in the final FIP on the relevant Class I areas. To effectively evaluate the impact of NOx reductions on regional haze, this level of analyses should have been conducted by EPA before publishing and finalizing the taconite BART FIP for Minnesota and Michigan.

Nonetheless, the first step in any photochemical modeling exercise is to ensure that the modeling results can be replicated to ensure no errors in the data transfer or modeling setup. Barr worked with MPCA to obtain the 2002 and 2005 modeling input files, run scripts, and post-processing files to allow for the validation of the Barr modeling system. To be clear, the modeling comparison scenario used the exact same files provided by MPCA with no adjustments. Given the length of time required to complete the modeling analyses, this step focused on the 2002 dataset and evaluated the results from the 2002 baseline and 2002 Minnesota BART SIP. The information provided by MPCA to complete this comparison was contained in the document: “Visibility Improvement Analysis of Controls Implemented due to BART Determinations on Emission Units Subject-to-BART”, October 23, 2009. The results of the comparison are contained in Appendix B: Barr and MPCA $\mathrm{CAM_X}$ Modeling Comparison of Results. As expected with any photochemical model comparison running four different quarterly simulations using two different computer systems and Fortran compilers, there are insignificant differences in the end values. The overall comparison of the results was very favorable and showed excellent agreement between the four modeled datasets (i.e. 2002 baseline and 2002 BART SIP, each from MPCA and Barr).

After successful confirmation of the consistency check of the Barr modeling system to the MPCA system, the modeling focused on the specific emission changes in the MPCA elevated point source files. As with most regional modeling applications, there were 36 “core” point source files for each scenario. This set corresponds to three files per month (Saturday, Sunday, and weekday) for all twelve months. Emission information from each file was extracted for all the CNR and Arcelor taconite facilities in Minnesota to confirm the emission totals used by MPCA in the SIP baseline and BART SIP control scenarios. The emission summary data for each unit matched the summary tables within the MPCA BART SIP modeling. Also, the emission sources from Tilden Mining Company in Michigan were identified and information extracted to allow for the same type of modeling as was conducted for the Minnesota facilities.

The next step was to include United Taconite Line 1 in the baseline and FIP modeling files. Line 1 was not originally included in the MPCA modeling because it was not operational in the 2002 base year.

Therefore, the information for that source was obtained from MPCA-provided 2018 elevated point source files and incorporated into the 36 core elevated point source files. This allowed all the CNR and Arcelor furnace lines within the FIP to be evaluated as part of this modeling analysis. To that end, each CNR and Arcelor BART-eligible source was specifically identified and labeled for processing to track modeled impacts using plume-in-grid treatment and the Particulate Source Apportionment Technology (PSAT) contained within CAM_X (including Tilden Mining). A list of the sources that were included in the specific PSAT groups can be found in Appendix C: CAM_X PSAT Source List.

As part of the identification and labeling process, the MPCA BART SIP elevated point source files were converted from binary input files to ascii text files using the BIN2ASC program. (NOTE: by using the BART SIP point source files, all other Minnesota BART-eligible sources were included in this modeling exercise using their BART SIP emissions to isolate the impacts of the CNR and Arcelor units.) Then, a Fortran90 program was developed to adjust the hourly emissions from each applicable source to correspond to the sum of annual emissions within each of the following scenarios: EPA FIP baseline and EPA final FIP. It is important to note that the temporal factors for each source were not modified from the original MPCA-provided inventory files (i.e. no changes to the monthly or day-of-week factors). This emission approach allowed for the exact set of emissions within each of the scenarios to be modeled. After the emissions within the text file were adjusted, the emissions were checked for accuracy. Then, each file was converted back to binary input from ASCII text using the ASC2BIN program. The emission summary for each unit/scenario combination is contained in Appendix D: Summary of CAM_X Elevated Point Source Emissions. Appendix D also provides a reference list for the emissions from the proposed FIP, Final FIP (where applicable), and calculation methodology where EPA did not provide sufficient information to calculate emissions. Table 1 contains a facility summary for all taconite furnaces under each scenario.

As stated previously, one of the outcomes of these analyses was the comparison of EPA's scalar approach to specific photochemical modeling using EPA's emission reduction assumptions within the FIP rulemakings. These modeling analyses make no judgment as to the achievability of these emission reductions. CNR and Arcelor dispute that these NOx reductions are achievable for all furnaces. These modeling analyses are, therefore, a conservative evaluation of EPA's predicted NOx reductions – not the actual NOx reductions achievable by the application of BART.

Table 1: Facility Taconite Furnace Emission Summary

Facility	FIP Baseline (TPY)		Final FIP (TPY)		Difference (TPY)	
	SO2	NOx	SO2	NOx	SO2	NOx
Arcelor Mittal	179	3,639	179	1,092	0	2,547
Hibbing Taconite	570	6,888	570	2,066	0	4,821
United Taconite	4,043	5,330	1,969	1,599	2,074	3,731
Northshore Mining	73	764	73	229	0	535
Tilden Mining	1,153	4,613	231	1,384	922	3,229
Total	**6,018**	**21,233**	**3,022**	**6,370**	**2,996**	**14,863**

Two other issues should be noted here.

1. The first is the nested 12-km modeling domain selected by MPCA (illustrated in Figure 1) along with the specific “receptors” used for identification of the relevant Isle Royale Class I area and their use for determination of impacts from Tilden Mining Company. The Tilden Mining source was not included in the MPCA fine grid as it was not part of the Minnesota SIP. However, the elevated point source file includes the sources in the entire 36 km domain (including Tilden). As such, the Tilden emissions were available for estimation of specific visibility impacts. The receptors selected by MPCA only included the western half of the Isle Royale Class I area because that is the portion of the area closest to the Minnesota sources. However, the size of the grid cells (e.g. 12 and 36 km) provides a large number of potential receptors at all the Class I areas and little variation among receptors is expected at the distance between Tilden and Isle Royale. Thus, the modeling data should adequately represent the visibility impact at the entire Isle Royale Class I area.

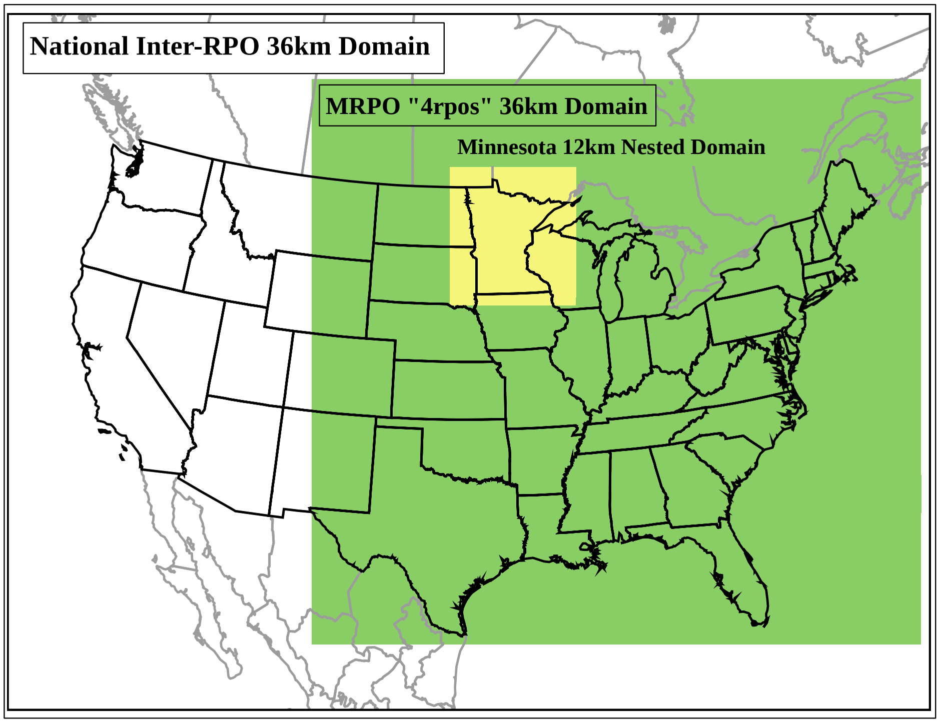

Figure 1. MPCA Modeling Domain

2. The second issue is the inconsistency between the emission reduction estimates used by EPA in the calculation of their scalar visibility benefits (i.e. Tables V-C of the proposed and final FIP) and the emission reductions calculated in the facility-specific sections of the proposed FIP. EPA's flawed calculation methodology did not use the appropriate emission reductions. In order to calculate the emissions for evaluation of the final FIP in the CAM_X modeling, Barr was left with utilizing the limited information provided in the proposed and final FIP rulemaking. The lack of information and the errors and inconsistencies within the dataset were highlighted in the information request on January 31, 2013 to EPA (included in Appendix E). As of the time of this memorandum, no response by EPA has been received by Barr. Further, given the time required to complete the modeling, assumptions were made that were conservative to calculate the FIP emissions. For example, the final FIP references a 65% NO_X reduction from Tilden Mining Company due to the switch to natural gas firing, but that was not consistent with the other gas-fired kilns (proposed FIP reduction was 70% with the same 1.2 lb NO_X/MMBTU emission limit). Therefore, to provide the maximum emission reductions, the 70% control was utilized for all the CNR and Arcelor taconite furnaces.

II. Summary of CAM$_X$ Results

As mentioned above, the CAM$_X$ model was executed for each calendar quarter of 2002 and 2005 using the adjusted emissions for each scenario. The results were then post-processed to calculate visibility impacts for each scenario in deciviews (dV). All these results are provided in Appendix F: CAM$_X$ Results by Facility. For the purposes of this memorandum, the following tables compare EPA's estimates of annual average impact contained within the proposed FIP with the results generated by the CAM$_X$ modeling for this project on a facility by facility basis. The first three facilities contain emission reductions for only NO$_X$: Arcelor Mittal, Hibbing Taconite, and Northshore Mining. These results are summarized in Tables 2-4. United Taconite and Tilden Mining, which have both SO_2 and NO$_X$ emission reductions, have result comparisons that require additional discussion.

The context of these results includes the following visibility impact thresholds:

0.5 dV impact is the BART eligibility and contribute to visibility impairment threshold (i.e. if a facility has less than 0.5 dV impact in the baseline, no BART is required)[2],

1.0 dV difference is the presumed human perceptible level for visibility improvement, and

0.1 dV difference was defined by other agencies, such as the northeastern states MANE-VU Regional Planning Organization[3] as the degree of visibility improvement that is too low to justify additional emission controls. In addition, EPA's Regional Haze Rule mentions[4] that "no degradation" to visibility would be "defined as less than a 0.1 deciview increase."

The first two columns within Tables 2-4 and 6-8 provide the difference in 98th percentile visibility improvement from the baseline to the FIP control emissions, while the third column provides a measure of over-estimation when using the EPA scalar approach (i.e. % Over Estimation by EPA = EPA Estimated Difference / CAM$_X$ Modeled Difference).

Table 2: Arcelor Mittal Visibility Impact Comparison

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[2] 40 CFR Part 51, Appendix Y – Guidelines for BART Determinations under the Regional Haze Rule.

[3] As documented by various states; see, for example, www.mass.gov/dep/air/priorities/hazebart.doc, which indicates a visibility impact of less than 0.1 delta-dv is considered "de minimis".

[4] 64 FR 35730.

Class I Area	EPA Estimated Difference 98% dV		CAM$_X$ Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	1.7		0.1		1500%
Voyageurs	0.9		0.09		1000%
Isle Royale	1.1		0.03		3700%

Table 3: Hibbing Taconite Visibility Impact Comparison

Class I Area	EPA Estimated Difference 98% dV		CAM$_X$ Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	3.2		0.19		1700%
Voyageurs	1.7		0.11		1500%
Isle Royale	2.1		0.04		5300%

Table 4: Northshore Mining Visibility Impact Comparison

Class I Area	EPA Estimated Difference 98% dV		CAM$_X$ Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	0.6		0.01		6000%
Voyageurs	0.3		0.01		3000%
Isle Royale	0.4		0.01		4000%

As pointed out in the previous comments on this proposed FIP, these results clearly demonstrate that the NOx reductions proposed in the FIP will not provide a perceptible visibility improvement. Additionally, it demonstrates that the EPA methodology using scalars severely overestimated the visibility impact from NO_X emission reductions at these taconite furnaces in northeast Minnesota. Even when using maximum emission reductions from EPA's baseline, the EPA estimates grossly over predicted the potential dV improvement by over <u>10 times</u> the predicted 98th percentile visibility improvement in all cases for the Arcelor Mittal, Hibbing Taconite, and Northshore Mining facilities. The maximum 98th percentile visibility improvement predicted by the source specific tracking for any one line was 0.1 dV (Arcelor Mittal Line 1 on Boundary Waters). The minimum 98th percentile visibility improvement was 0.01 dV (Northshore Mining on Isle Royale). Further, the results presented in Table 5 for the individual furnace line impacts at Hibbing Taconite illustrate de minimis visibility improvement at all the Class I areas evaluated.

Table 5: Hibbing Taconite Line-Specific Visibility Impacts

Class I Area	Furnace Line		CAM_X Modeled Difference 98% dV
Boundary Waters	Line 1		0.04
	Line 2		0.05
	Line 3		0.08
Voyageurs	Line 1		0.03
	Line 2		0.04
	Line 3		0.04
Isle Royale	Line 1		0.01
	Line 2		0.01
	Line 3		0.01

Overall, all the facilities with only NO_X emission reductions predict visibility improvement from each furnace line at or below the de minimis visibility improvement threshold of 0.1 delta-dV.

Due to the sizable change in the United Taconite SO_2 emission reductions from the proposed FIP to the final FIP; the visibility improvement was re-calculated using EPA's apparent methodology from the proposed FIP. The EPA scalars (proposed FIP – Table V – C.9) were applied for each pollutant using the corrected emission reduction for NO_X and the revised emission reduction for SO_2. Then, those resultants were averaged for each of the Class I areas to obtain the "updated" EPA all pollutant estimates.

Table 6: United Taconite Visibility Impact Comparison (All Pollutants)

Class I Area	Amended EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	1.6		1.40		110%
Voyageurs	0.8		0.85		N/A
Isle Royale	1.1		0.35		320%

The comparison of the total modeling effort including both pollutant reductions is surprisingly similar (except for Isle Royale). However, when the individual pollutant impacts are examined, the problem with EPA's methodology is more clearly understood. The sulfate impacts are estimated more closely to the CAM_X results, while the nitrate impacts are grossly overestimated similar to the first three facilities.

The methodology used to isolate the sulfate and nitrate impacts separately from the current CAM_X results prioritizes the sulfate and nitrate impacts as part of three separate post-processing runs (all pollutants, sulfate, and nitrate). The sulfate impact was derived by sorting the visibility impacts at each receptor from each scenario by maximum sulfate contribution for each line. Likewise, the nitrate impact was derived by sorting the visibility impacts at each receptor from each scenario by maximum nitrate contribution for each line. Then, the results were summed for both lines to obtain the overall United Taconite impact by pollutant. In nearly all circumstances, this will overestimate the impact of the NO_X control. This is due to the impact from the sulfate reductions that drives the total visibility impact with a much smaller percentage from the nitrate reductions. When the nitrate impact is maximized by the sorting technique, the overall impact on the same day could be very small (e.g. nitrate = 0.1 dV; total = 0.15 dV) and would not show up as part of the overall visibility change. As detailed in the comments to the proposed FIP, it is also important to note the high probability that the maximum impacts from NO_X emission reduction occur during the winter months when Isle Royale is closed to visitors and visitation at the other Class I areas is significantly reduced from summertime maximum conditions.[5]

Table 7: United Taconite Visibility Impact Comparison (Sulfate Impact)

Class I Area	Amended EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	1.0		1.29		N/A
Voyageurs	0.5		0.74		N/A
Isle Royale	0.6		0.28		210%

Table 8: United Taconite Visibility Impact Comparison (Nitrate Impact)

Class I Area	Amended EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	2.3		0.18		1300%
Voyageurs	1.1		0.08		1400%
Isle Royale	1.6		0.05		3200%

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[5] Cliffs Natural Resources (September 28, 2012), EPA-R05-OAR-0037-0045 Att. M

In the same manner as Hibbing Taconite, United Taconite's individual furnace lines were evaluated. As mentioned in the previous paragraph, the results in Table 9 for nitrate impact are biased toward higher nitrate impacts due to the sorting of the data to maximize nitrate impact.

Table 9: United Taconite Line-Specific Nitrate Visibility Impacts

Class I Area	Furnace Line		CAM_X Modeled Difference 98% dV
Boundary Waters	Line 1		0.05
	Line 2		0.1
Voyageurs	Line 1		0.02
	Line 2		0.06
Isle Royale	Line 1		0.02
	Line 2		0.03

Nonetheless, as seen for all the other furnace lines, the results for United Taconite's predicted visibility impact are at or below the deminimis threshold for visibility improvement.

Since Tilden Mining Company was not evaluated using the same methodology as the Minnesota taconite facilities, there are no specific EPA data to compare with the CAM_X results. However, it is important to understand that the results are very similar to the other results regarding the impact of NO_X emission reductions on these Class I areas.

Table 10: Tilden Mining Visibility Impact Comparison (All Pollutants)

Class I Area	EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV
Boundary Waters	N/A		0.08
Voyageurs	N/A		0.03
Isle Royale	N/A*		0.17

*EPA estimated that the proposed FIP results in 0.501 dV visibility improvement at Isle Royale from emission reduction at Tilden Mining

Table 11: Tilden Mining Pollutant-Specific Impact Comparison

Class I Area	CAM_X Sulfate Modeled Difference 98% dV		CAM_X Nitrate Modeled Difference 98% dV
Boundary Waters	0.07		0.01
Voyageurs	0.03		0.00
Isle Royale	0.14		0.02

The visibility impacts from NO_X emission reductions at Tilden are consistent with the other modeling results and further demonstrate that significant emission reductions of NOx (3,229 tpy for Tilden) result in no visibility improvements.

III. Conclusions

Overall, the results from the three facilities with only NO_X emission reductions (Hibbing Taconite, Northshore Mining, and Arcelor Mittal) and the pollutant-specific comparisons for United Taconite and Tilden Mining illustrate that nearly 15,000 tons per year of NO_X reductions, even if they were technically and/or economically achievable, provide imperceptible visibility impacts at the Minnesota or nearby Michigan Class I areas. In all cases, the CAMx-predicted impacts for every furnace line are at or below the de minimis threshold for visibility improvement (0.1 delta-dV).

The fact that NO_X emission reductions do not provide perceptible visibility improvement was understood by MPCA when they proposed existing control and good combustion practices as BART for taconite furnaces in northeast Minnesota. This finding has been confirmed by this detailed modeling analysis. EPA, to its credit, does not claim that its scalar "ratio" approach for predicting visibility improvement is accurate. In the final FIP, EPA provided, "Therefore, even if the ratio approach was over-estimating visibility improvement by a factor of two or three, the expected benefits would still be significant."[6] Our analysis demonstrates that the ratio approach has over-estimated impacts by a factor of ten to sixty for NO_X reductions. When accurately modeled, the NO_X reductions do not yield discernible visibility benefits. To that end, the following pictures from WinHaze Level 1 Visual Air Quality Imaging Modeler

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[6] Federal Register, Volume 78, Number 25, page 8720, February 6, 2013

(version 2.9.9.1) provide a visual reference for the CAM_X predicted visibility impairment from the maximum nitrate impacting facility at Isle Royale and Boundary Waters[7].

Isle Royale FIP Base – United Taconite

Isle Royale Final FIP – United Taconite

Boundary Waters FIP Base – Hibbing Taconite

Boundary Waters Final FIP – Hibbing Taconite

Given the size of the predicted visibility impacts (both less than 0.2 dV improvement), these pictures illustrate no discernible visibility improvement from NO_X reductions at either Class I area.

Ultimately, Minnesota and Michigan reached their visibility assessments in different ways, but this modeled analysis supports their conclusion that low NO_X burner technology is not BART for the furnaces modeled at Arcelor Mittal - Minorca, Hibbing Taconite, Northshore Mining Company, United Taconite, and Tilden Mining. Therefore, EPA should approve the sections of the SIPs establishing NO_X BART on this basis.

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[7] Voyageurs National Park pictures are not contained within the WinHaze program

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BARR

APPENDIX A: Visibility Impact Requirements and EPA's Scalar Approach for Estimating Visibility Impacts within the Taconite FIP

March 6, 2013

I. Summary of Visibility Impact Requirements

The relevant language related to the specific BART visibility impact modeling approach from 40 CFR 51 Appendix Y (herein, Appendix Y), *Guidelines for BART Determinations Under the Regional Haze Rule,* is provided here, in italics with some language underlined for emphasis:

5. Step 5: How should I determine visibility impacts in the BART determination?

- *For each source, run the model, at pre-control and post-control emission rates according to the accepted methodology in the protocol.*

Use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled (for the pre-control scenario). Calculate the model results for each receptor as the change in deciviews compared against natural visibility conditions. Post-control emission rates are calculated as a percentage of pre-control emission rates. For example, if the 24-hr pre-control emission rate is 100 lb/hr of SO[2], then the post control rate is 5 lb/hr if the control efficiency being evaluated is 95 percent.

- *Make the net visibility improvement determination.*

Assess the visibility improvement based on the modeled change in visibility impacts for the pre-control and post-control emission scenarios. You have flexibility to assess visibility improvements due to BART controls by one or more methods. You may consider the frequency, magnitude, and duration components of impairment. Suggestions for making the determination are:

  - *Use of a comparison threshold, as is done for determining if BART-eligible sources should be subject to a BART determination. Comparison thresholds can be used in a number of ways in evaluating visibility improvement (e.g., the number of days or hours that the threshold was exceeded, a single threshold for determining whether a change in impacts is significant, or a threshold representing an x percent change in improvement).*
  - *Compare the 98th percent days for the pre- and post-control runs.*

Note that each of the modeling options may be supplemented with source apportionment data or source apportionment modeling.

It should be noted that Appendix Y is a guideline for state air quality agencies to proceed with modeling of BART sources. Therefore, these are not requirements, but recommended practices for evaluation of visibility impacts. Significant discretion was given to each state regarding the use of these methods. To that end, the Minnesota Pollution Control Agency applied a different modeling system than the EPA-approved model (CALPUFF) for BART evaluations. Discussed below, the new modeling system was subsequently used by EPA as part of their FIP proposal.

Further, an excerpt from the Clean Air Act, Part C, Subpart II is provided below to establish the basis for the Appendix Y regulations related to visibility improvement.

II. Summary of EPA's approach

Specific language from the proposed and final FIPs are provided in *italics* along with comments.

EPA relied on visibility improvement modeling conducted by the Minnesota Pollution Control Agency (MPCA) and recorded in MPCA's document "Visibility Improvement Analysis of Controls Due to BART Determinations on Emission Unit's Subject to BART", October 23, 2009 [attached]. The visibility improvement modeling conducted by MPCA utilized the Comprehensive Air Quality Model with Extensions (CAMx) air quality model with the Mesoscale Meteorological Model (MM5) and the Emission Modeling System (EMS-2003). Within the CAMx modeling system, MPCA used the Particulate Source Apportionment Tool (PSAT) and included evaluation of all the elevated point emissions[1] at each facility with best available retrofit technology (BART) units. The impacts from MPCA State Implementation Plan (SIP) BART controls were determined by subtracting the impact difference between the 2002/2005 base case and 2002/2005 BART control case for each facility. EPA used the impacts from four of the six facilities modeled by MPCA (Minnesota Power – Boswell Energy Center, Minnesota Power – Taconite Harbor, Northshore Mining – Silver Bay, United Taconite). The other two facilities modeled by MPCA were utility sources (Rochester Public Utilities – Silver Lake and Xcel Energy – Sherburne Generating Plant). The locations of these sources are presented below in Figure A-1 (obtained from the MPCA 2009 document).

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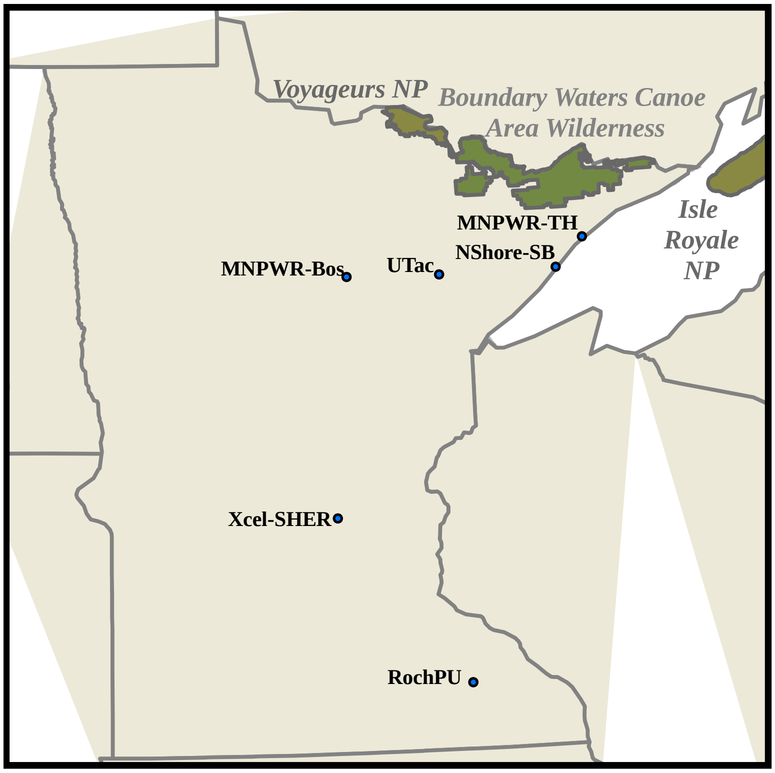
[1] Elevated point emissions include only sources with plume rise above 50m.

Figure A-1: Minnesota Facilities with BART-Determinations Assessed



In order to avoid the time and effort necessary for specific modeling of the units that EPA proposed to include in the FIP, EPA then used the average visibility impact from these four facilities to calculate two metrics for visibility improvement. The first metric is a ratio of number of days with greater than 0.5 deciview (dV) visibility divided separately by the change in SO_2 and NO_X emissions at each facility (i.e. one ratio for change in SO_2 emissions and one ratio for change in NO_X emissions). The second metric was calculated in the same fashion, but with 98th percentile visibility change divided by the change in SO_2 and NO_X emissions at each facility. These ratios were then multiplied by the estimated FIP emission reductions for the taconite facilities (including UTAC and Northshore Mining). It is important to note that there were no NO_X emission reductions modeled from any of the taconite facilities and the only source of SO_2 emission reductions from the taconite facilities was the UTAC facility.

Within the final FIP, EPA provided some additional statements that further clarified the agency's confidence regarding the use of the scalar approach for estimating visibility improvements.

III. Specific Issues Regarding EPA's Visibility Impact Estimates

Clean Air Act Section 169(A)(g)(2) – "In determining the best available retrofit technology the State (or the Administrator in determining emission limitations which reflect such technology) shall take into consideration the costs of compliance, the energy and nonair quality environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology."

Proposed FIP Page 49329 – Column 1 – "The discussion below uses MPCA's emissions data and modeled visibility impact data to derive visibility impact ratios as a function of changes in emissions of NOx and SO2 at MPCA-modeled facilities. These visibility-emission ratios were then applied to the BART-based emission changes for the source subject to this BART rule to derive possible visibility impacts."

Issues – EPA's shortcut methodology does not provide an accurate assessment of potential visibility impacts from taconite emission units subject to BART, and cannot be relied upon for several reasons stated below. The use of emission change vs. visibility impact ratios is not scientifically accurate even for a single source, much less several sources in other locations, and illustrates EPA's haste for the development of the FIP without proper modeling procedures. According to a plain language reading of the Clean Air Act section above and the best-practice recommendations within Appendix Y, the state and EPA were required to conduct a thorough evaluation of the impacts associated with the changes in emissions for each BART technology at the relevant units within each taconite facilities. EPA's methodology does not result in a thorough evaluation. If such an analysis were submitted to EPA by the state, it would be rejected as inadequate. The same should apply to EPA's analysis of the visibility improvement calculations.

MPCA used an appropriate model for estimating visibility impacts from five utility sources and one taconite source, all subject to BART, in northern Minnesota. EPA took that analyses and attempted to justify its outcomes based on its flawed methodology. Alone, the differences between the emission profiles for utility sources and taconite sources and their different locations relative to the Class I areas should preclude this type of evaluation. The difference in the emissions profile relationship between NO_X and SO_2 emissions is extremely important due to the interactive and competitive nature of the two pollutants for available ammonia (NH_3) to form ammonium nitrate or ammonium sulfate.

In addition, there are important seasonal differences in the tendency for sulfates or nitrates to be important for haze formation. Nitrates are only important in winter because significant particle formation occurs only in cold weather; oxides of nitrogen react primarily to form ozone in the summer months. On the other hand, oxidation of SO_2 to sulfate is most effective in summer with higher rates of photochemical and aqueous phase reactions. Due to the much different seasonal preferences for these two haze components, a one-size-fits-all scaling approach based upon annual averages that is insensitive to the season of the year is wholly inappropriate.

It is important to note that the only NO_X emission reductions used in the EPA scalar analyses were from utility sources. This occurred because the MPCA SIP did not include NO_X emission reductions from the United Taconite units. Therefore, the variation in emission profiles and stack parameters between utility boiler emission sources and taconite furnaces introduce another source of error with the EPA methodology.

Further, as shown in Figure A-1, the location of these sources with respect to the relevant Class I areas also causes significant problems with the EPA evaluation. The modeled visibility impacts from each source are a direct function of the wind direction. When two sources are not in the same direction with respect to the area, there is no possible way to accurately reflect the impact from the two different sources on receptor locations on any given day. For example, elevated impacts on the Voyageurs National Park from Northshore Mining would not happen on the same days as any of the other taconite sources in Minnesota.

Additionally, notwithstanding the inaccuracies of EPA's average scalar methodology, a review of the calculation of the visibility change to emission reduction ratios (i.e. MPCA-calculated visibility changes divided by SO_2 and NO_X SIP emission reductions) was conducted. This review uncovered calculation/typographical errors in the tables that were used to develop the average visibility change metrics. These simple calculation errors were subsequently corrected in the final FIP, but another inconsistency was not. The emission reductions used for NO_X within the scalar visibility calculations (Table V-C.xx) do not match the emission reduction tables in the proposed FIP (Table V – B.yy) for each facility. In one case (Northshore Mining Company), the visibility improvement reductions are greater than the baseline emissions. The attached table provides the baseline, proposed FIP, and final FIP information contained within the EPA rulemakings and docket for each taconite furnace and facility. Ultimately, even if the scalar approach used by EPA was valid, the rulemaking record is inaccurate and incomplete for the calculation of visibility impacts due to these inconsistencies.

Further, the calculation methodology for the two facilities with SO_2 and NO_X reductions (United Taconite and US Steel – Minntac) appears to utilize another invalid assumption. Also, the proposed FIP does not provide a clear explanation of the calculation of the scaled visibility impacts for these two facilities (Page 49332 – Column 1):

"To calculate the visibility impacts for the Minnesota source facilities covered by this FIP proposed rule, we multiplied the total estimated BART NOx and SO2 emission reductions for each subject facility by the appropriate visibility factor/emission change ratios in Table V-C.9 and combined the results to estimate the total visibility impacts that would result from the reduction of PM2.5 concentrations."

In Tables V-C.14 and V-C.16, the calculation of the visibility change with the two different pollutants is not explicitly provided within the FIP. Based on the use of the average visibility changes ("combined results") in the attached tables, one can generate "estimated visibility impacts" that are close to the values provided in the FIP tables. This pollutant averaging approach is not valid due to the previous comments regarding the interactive nature of the reaction mechanisms for ammonium nitrate and ammonium sulfate.

Proposed FIP Page 49331 – Column 1 – "The above visibility factor/emission change ratio data show significant variation from source-to-source and between impacted Class I areas. This variation is caused by differences in the relative location of the source (relative to the locations of the Class I areas), variations in background sources, variations in transport patterns on high haze factors, and other factors that we cannot assess without detailed modeling of the visibility impacts for the sources as a function of pollutant emission type."

Issue – EPA correctly establishes the significant variation in the ratio data and clearly distinguishes some (but not all) of the problems with the approach used to determine visibility impacts. Other problems include the differences in modeled utility source stack parameters vs. taconite stack parameters, the different inter-pollutant ratios at each facility, and the differences in visibility impacts due to on-going changes in emissions from 2002/2005 to current/future emission levels. Furthermore, EPA identifies the solution to solve this problem within their statement regarding "detailed modeling of the visibility impacts". This detailed modeling exercise was completed for BART-eligible Cliffs Natural Resources and Arcelor Mittal facilities in northeast Minnesota and Michigan to provide a clear record of the visibility improvements associated with the final FIP. This modeling demonstrates the lack of visibility improvement from nearly 15,000 tons per year of NO_X emission reductions and provides sufficient evidence to support the Minnesota and Michigan State Implementation Plans which called for good combustion practices as BART for NO_X at these facilities.

Proposed FIP Page 49333, Column 2 – "Each BART determination is a function of consideration of visibility improvement and other factors for the individual unit, but in general EPA's assessment of visibility impacts finds that technically feasible controls that are available at a reasonable cost for taconite plants can be expected to provide a visibility benefit that makes those controls warranted."

Issue – EPA's statement regarding visibility benefit from the FIP NO_X emission reductions are vastly overestimated based on updated CAM_X modeling for the Cliffs Natural Resources and Arcelor Mittal taconite furnaces. The modeling results evaluating the 98th percentile visibility improvements obtained from these emission reductions are generally less than 10% of the EPA estimates. Therefore, these NO_X controls are not warranted for visibility improvement in northeast Minnesota and Michigan.

Final FIP Page 8720, Column 2 – "EPA's analysis shows that based on all of the BART factors, including visibility, the selected controls are warranted. If highly reasonable and cost-effective controls had been available but visibility benefits were slight, EPA would have rejected those controls."

Issue – EPA describes exactly the situation with respect to "slight visibility benefits". Therefore, given the new information regarding the very slight modeled impact of NO_X emission reductions, EPA should reject those reductions as necessary under the BART program. Also, in the final FIP, EPA criticizes both MPCA and MDEQ for ignoring relevant information on Low NO_X Burner (LNB) technology. Now, given the length of time necessary and extensive effort required to generate this new visibility improvement data, EPA should reconsider its position on LNB as producing visibility benefits. This would allow EPA to support the original findings for these facilities within both the MPCA and MDEQ SIP with respect to NO_X emission limits.

Final FIP Page 8720, Column 3 – "EPA's proposed rule acknowledged the uncertainty associated with the visibility impact ratio approach, but noted that despite the uncertainties, the Agency was confident that the information was adequate to assess potential visibility improvements due to emission reductions at the specific facilities."

"Given the geographic proximity of the taconite facilities to those that were modeled, EPA believes that the ratio approach provide adequate assurance of the visibility improvements that can be expected from the proposed emission reductions."

"In the proposed rule's summary of the impacts at Boundary Waters, Voyageurs, and Isle Royale, these values ranged from 1.3 to 7.1 dVs of improvement with between 17 and 93 fewer days above the 0.5 dV threshold. Therefore, even if the ratio approach was over-estimating visibility improvements by a factor of two or three, the expected benefits would still be significant."

Final FIP Page 8721, Column 3 – "EPA stands by the results of its ratio approach and believes that it produced reasonable results for the sources examined."

Issue – EPA again chose to ignore the specific technical issues discussed above regarding the use of the ratio approach and has incorrectly assumed that this approach will provide an accurate assessment of the visibility benefits from the Cliffs and Arcelor taconite facilities. Based on the refined CAM_X modeling results using a conservative estimate of EPA's final FIP emission reduction scenario, it is obvious that the ratio approach does not provide any assurance of the visibility improvements. Further, the estimates for visibility improvement are over-estimated by between a factor of ten and sixty. Therefore, the impacts are not "significant" as referenced in EPA's response to comment within the final FIP rulemaking. The lack of technical validity contained within the EPA scalar approach is alarming. Even more alarming is the agency's refusal to conduct the type of detailed analyses necessary to allow for a technically valid answer on a rulemaking that will cost the taconite industry millions of dollars.

IV. Summary

The CAM_X modeling approach undertaken by Cliffs and Arcelor provides the best approximation of the visibility improvements from the emission reductions within the final FIP. This method replaces the use of the average ratio approach used by EPA with refined, photochemical modeling for the Cliffs and Arcelor facilities. The results of the analysis confirm the findings of the MPCA in its 2009 SIP that NO_X emission reductions do not have sufficient impact to warrant further consideration. At this point, we affirm that EPA's simple assessment is not credible, and any visibility improvement conclusions for NO_X are not technically sound. The visibility improvement results estimated by EPA using the ratio approach are between ten and sixty times greater than the results generated using the CAM_X modeling system. In essence, the modeling conducted here provides EPA another opportunity to support the findings of the MPCA and MDEQ SIPs with respect to NO_X emissions impacts at the Cliffs and Arcelor facilities.

Cliffs Natural Resources and Arcelor Mittal Taconite FIP Emission Summary

				Emissions			Emission Reductions			Emissions	
				Proposed FIP			Baseline - Prop FIP	Baseline - Prop FIP		Final FIP	
Facility	Emission Unit		Pollutant	Baseline	FIP		Emission Tables	Visibility Calcs			
	ModID	Description		tons/yr	tons/yr	Note(s)	tons/yr	tons/yr	Note(s)	lb/hr	Note(s)
Hibbing Taconite Company	{3}	Line 1	NOx	2,497	749	[1]	1,748				[4]
			SO2	202	202	[2]	0			82.6	[5]
	{4}	Line 2	NOx	2,144	643	[1]	1,500				[4]
			SO2	180	180	[2]	0			82.6	[5]
	{5}	Line 3	NOx	2,247	674	[1]	1,573				[4]
			SO2	188	188	[2]	0			82.6	[5]
	HTC	BART Units Combined	NOx	6,888	2,066		**4,821**	**5,259**	[3]		
			SO2	570	570		0	0	[3]	247.8	
Northshore Mining Company		Process Boiler 1/2	NOx	41	21	[6]	21				[10]
			SO2								
	{24}	Furnace 11	NOx	386	116	[7]	270				[11]
			SO2	38	38	[8]	0			19.5	[12]
	{25}	Furnace 12	NOx	378	113	[7]	264				[11]
			SO2	35	35	[8]	0			19.5	[12]
	NSM	BART Units Combined	NOx	805	250		**555**	**926**	[9]		
			SO2	73	73		0	0	[9]	39	
Tilden Mining Company	{1}	Boiler #1/2	NOx	79	79	[13]	0				
			SO2	0	0	[14]	0				[19]
	{3}	Ore Dryer # 1	NOx	15	15	[15]	0				
			SO2	34	34	[15]	0				[20]
	{5}	Furnace #1	NOx	4,613	1,384	[16]	3,229				[21]
			SO2	1,153	115	[17]	1,038			55	[22][23]
	TMC	BART Units Combined	NOx	4,707	1,478		3,229	3,229	[18]		
			SO2	1,187	150		1,038	1,038	[18]		
United Taconite	{26}	Line 1	NOx	**1,643**	493	[24]	1,150				[27]
			SO2	1,293	129	[25]	1,164			155	[28]
	{24}	Line 2	NOx	**3,687**	1,106	[24]	2,581				[27]
			SO2	2,750	275	[25]	2,475			374	[28]
	UTAC	BART Units Combined	NOx	5,330	1,599		**3,731**	**3,208**	[26]		
			SO2	4,043	404		3,639	3,639	[26]	529	[28]
Arcelor Mittal	ARC {12}	Line 1	NOx	3,639	1,092	[29]	**2,547**	**2,859**	[31]		[32]
			SO2	179	179	[30]	0	0	[31]	38.2	[33]

TOTAL BART UNIT	NOx	21,369	6,485		14,884	15,481
	SO2	6,053	1,376		4,677	4,677

🟨 Facility BART Unit Summary or Overall Summary
🟩 FIP Baseline does not match reference
🟧 FIP Table B emission tables do not match Table C visibility calculation tables

EPA Furnace
NOx Control %
70%

Notes:

[1] HTC Line 1-3 - USEPA FIP NOx Baseline Emissions Proposed FIP Table V - B.24 ; Proposed FIP NOx Emissions = 70% Control from Baseline
Typographical Error in Table V - B.24 for Line 1 Baseline Emissions (2,143.5 TPY Proposed FIP; should have been 2,497 TPY)
[2] HTC Line 1-3 - USEPA FIP SO2 Baseline Emissions from Proposed FIP Table V - B.27
[3] HTC - USEPA Proposed BART FIP Table V - C.11
[4] HTC Furnace Lines - USEPA Final BART limit of 1.5 lb NOx/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only).
[5] HTC Furnace Lines - USEPA final BART combined limit of 247.8 lb SO2/hr [82.6 lb/hr each for Lines 1 to 3] (30-day rolling avg); can be adjusted based on CEMs data.
[6] NSM Process Boilers 1&2 - NOx Emissions from Proposed FIP Table V - B.12 (p49318); LNB 50% Control from Baseline of 41.2 tons/year
[7] NSM Furnace 11/12 - NOx Emissions (Baseline and Proposed FIP Control) from Proposed FIP - Table V - B.8; FIP Emisssions = 70% Control from Baseline
[8] NSM Furnace 11/12 - No Additional SO2 Control Applied by Proposed FIP; Baseline FIP Emission Rate from Table V - B.10
[9] NSM - USEPA Proposed BART FIP Table V - C.12
[10] NSM Process Boilers 1&2 - USEPA Final BART limit of 0.085 lb NOx/MMBTU (30-day rolling average) [No additional control].
[11] NSM Furnace 11/12 - USEPA Final BART limit of 1.5 lb NOx/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only).
[12] NSM Furnace 11/12 - USEPA final BART combined limit of 39.0 lb SO2/hr (30-day rolling average); must be adjusted based on CEMs data.
[13] Tilden Process Boilers 1 & 2 - NOx Baseline Emissions Proposed FIP Table V - B.38
[14] Tilden Process Boilers 1 & 2 - SO2 Baseline Emissions Proposed FIP Table V - B.37 (0.25 TPY)
[15] Tilden Dryer #1 _ Emissions from Proposed FIP Table V - B.39 (SO2) and Table V - B.40 (NOx) - 34.07 TPY SO2, 15.1 TPY NOx
[16] Tilden Furnace 1 - NO2 Baseline and Proposed FIP Control Emissions - Proposed FIP Table V - B.34 (FIP Emissions = 70% Control from Baseline)
[17] Tilden Furnace 1 - Proposed FIP SO2 Emissions - Table V-B.36; Spray Dry Absorption 90%; Proposed FIP Text says 95% Control or 5 ppm;
Baseline Emissions Back-calculated from 90% control
[18] Tilden Furnace 1 - USEPA did not calculate visibility improvement for Tilden (Used emission difference Baseline - Proposed FIP)
[19] Tilden - USEPA Final BART limit of 1.2%S in fuel combusted by Process Boiler #1 and #2
[20] Tilden - USEPA Final BART limit of 1.5%S in fuel combusted by Ore Dryer #1
[21] Tilden Furnace 1- USEPA Final BART limit of 1.5 lb NOx/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only);
NOx emissions referenced in final FIP text as 65% control from baseline (page 8721)
[22] Tilden Furnace 1 - USEPA Final BART restriction - Only combust natural gas in Grate Kiln Line 1 with limit computed in lb SO2/hr based on CEMs;
SO2 emissions referenced in final FIP text at 80% control from baseline (page 8721)
[23] Tilden Furnace 1 - USEPA Final BART Modeling File (Part of Final Rulemaking Docket) Conducted by NPS - 55 lb/hr SO2
[24] UTAC Line 1-2 - USEPA NOx Baseline Emissions Proposed FIP Table V - B.14 ; Proposed FIP NOx Emissions = 70% Control from Baseline
[25] UTAC Line 1-2 - USEPA proposed FIP Baseline SO2 Emissions Table V - B.17; 90% Control in Table, but 95% Control within text - Proposed FIP (page 49319)
[26] UTAC - USEPA Proposed BART FIP Table V - C.13
[27] UTAC Line 1-2 - USEPA Final BART NOx Limit of 1.5 lb/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only)
[28] UTAC Line 1-2 - USEPA Final BART SO2 Limit of 529 lb/hr Combined (155 lb/hr - Line 1 & 374 lb/hr - Line 2).
[29] Arcelor - USEPA proposed FIP Baseline NOx Emissions Table V - B.19; Proposed FIP NOx Emissions = 70% Control from Baseline
[30] Arcelor - USEPA proposed FIP Baseline SO2 Emissions Table V - B.21
[31] Arcelor - USEPA Proposed BART FIP Table V - C.10
[32] Arcelor - USEPA Final BART SO2 Limit of 38.16 lb/hr for Arcelor.
[33] Arcelor - USEPA Final BART NOx Limit of 1.5 lb/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only)

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APPENDIX B: Barr and MPCA CAM$_X$ Modeling Comparison of Results

March 6, 2013

Minnesota Power – Taconite Harbor (BART01)

MPCA

Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

PM$_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	94	90	-4	11	9	-2	30	27	-3
98th Percentile Δ dv	**2002**	9.2	8.3	-0.9	0.8	0.7	-0.1	2.2	1.9	-0.3

Barr

Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

PM$_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	95	90	-5	11	9	-2	30	27	-3
98th Percentile Δ dv	**2002**	9.14	8.25	-0.89	0.82	0.68	-0.14	2.22	1.88	-0.34

Minnesota Power – Boswell (BART04)

MPCA

Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

PM$_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Differ-Ence**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Differ-Ence**
Days > 0.5 dv	**2002**	111	60	-51	86	58	-28	48	27	-21
98th Percentile Δ dv	**2002**	4.3	2.4	-1.9	4.4	2.7	-1.8	2.0	1.0	-1.0

Barr

Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

PM$_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Differ-Ence**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	110	61	-49	86	58	-28	47	27	-20
98th Percentile Δ dv	**2002**	4.27	2.37	-1.90	4.43	2.65	-1.78	1.96	0.98	-0.98

Northshore Mining – Silver Bay (BART05)

MPCA

Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	77	72	-5	9	8	-1	20	15	-5
98th Percentile Δ dv	**2002**	3.96	3.79	-0.17	0.6	0.5	-0.1	0.9	0.7	-0.2

Barr

Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	78	72	-6	9	8	-1	20	15	-5
98th Percentile Δ dv	**2002**	3.96	3.78	-0.18	0.63	0.50	-0.13	0.90	0.73	-0.17

United Taconite (BART26)

MPCA

Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	59	44	-15	32	20	-12	8	1	-7
98th Percentile Δ dv	**2002**	3.0	1.7	-1.3	1.8	0.8	-0.9	0.6	0.3	-0.3

Barr

Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	63	46	-17	34	20	-14	8	1	-7
98th Percentile Δ dv	**2002**	3.02	1.69	-1.33	1.78	0.85	-0.93	0.59	0.28	-0.31

Xcel Sherburne (BART13)

MPCA
Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	74	58	-16	53	39	-14	42	30	-12
98th Percentile Δ dv	**2002**	2.5	1.9	-0.6	2.2	1.7	-0.5	1.4	1.0	-0.4

Barr
Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	74	59	-15	53	39	-14	42	29	-13
98th Percentile Δ dv	**2002**	2.48	1.90	-0.58	2.18	1.65	-0.53	1.44	1.06	-0.38

Rochester Public Utilities (BART07)

MPCA
Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	0	0	0	0	0	0	0	0	0
98th Percentile Δ dv	**2002**	0.1	0.1	0.0	0.1	0.0	0.0	0.1	0.0	0.0

Barr
Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	0	0	0	0	0	0	0	0	0
98th Percentile Δ dv	**2002**	0.10	0.06	0.04	0.08	0.04	0.04	0.09	0.04	0.05

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APPENDIX C: CAM$_X$ PSAT Source List

March 6, 2013

2009 MPCA Tracked, Elevated Point Sources

RANKTRAC BARTSRC_ID	RECEPTOR BARTSRC_ID	Facility ID	Facility Name [1]
1	2	2703100001	Minnesota Power - Taconite Harbor
2	3	2703700003	XCEL - Black Dog
3	4	2705300015	XCEL - Riverside
4	5	2706100004	Minnesota Power - Boswell
5	6	2707500003	Northshore Mining Co - Silver Bay
6	7	2709900001	Austin Utilities - NE Power Station
7	8	2710900011	Rochester Public Utilities
8	9	2711100002	Otter Tail Power - Hoot Lake
9	10	2712300012	XCEL - High Bridge
10	11	2713700013	Minnesota Power - Laskin
11	12	2713700027	Hibbing Public Utilities
12	13	2713700028	Virginia Dept of Public Utilities
13	14	2714100004	XCEL - Sherburne Generating Plant
14	15	2716300005	XCEL - Allen S. King
15	16	2701700002	Sappi - Cloquet
16	17	2703700011	Flint Hill Resources - Pine Bend
17	18	2706100001	Blandin Paper / Rapids Energy
18	19	2707100002	Boise Cascade - International Falls
19	20	2713700005	US Steel - Minntac
20	21	2713700015	Minnesota Power - ML Hibbard
21	22	2713700022	Duluth Steam Cooperative
22	23	2713700031	Georgia Pacific - Duluth
23	24	2713700061	Hibbing Taconite
24	25	2713700062	Arcelor Mittal
25	26	2713700063	US Steel - Keetac
26	27	2713700113	United Taconite - Fairlane Plant [2]
27	28	2700900011	International Paper - Sartell
28	29	2716300003	Marathon Ashland Petroleum
29	30	2713700083	Potlatch - Cook
30	31	2706100010	Potlatch - Grand Rapids

🟨	Included in MPCA BART SIP Modeling Report
[1]	MPCA tracked all point sources on a facility-basis
[2]	MPCA Emissions did not Include UTAC Line 1

2012/2013 Barr Tracked, Elevated Point Sources

Output ID	BARTSRC_ID	Facility ID	Facility / Unit Name [3]
MNPWTH	2	2703100001	Minnesota Power - Taconite Harbor
XCELBD	3	2703700003	XCEL - Black Dog
XCELRV	4	2705300015	XCEL - Riverside
MNPWBO	5	2706100004	Minnesota Power - Boswell
NSMSBU	6	2707500003	Northshore Mining Co - Silver Bay (All Other)
AUSTIN	7	2709900001	Austin Utilities - NE Power Station
ROCHPU	8	2710900011	Rochester Public Utilities
OTTRHL	9	2711100002	Otter Tail Power - Hoot Lake
XCELHB	10	2712300012	XCEL - High Bridge
MNPWLS	11	2713700013	Minnesota Power - Laskin
HIBBPU	12	2713700027	Hibbing Public Utilities
VIRGPU	13	2713700028	Virginia Dept of Public Utilities
XCELSB	14	2714100004	XCEL - Sherburne Generating Plant
XCELAK	15	2716300005	XCEL - Allen S. King
SAPPIC	16	2701700002	Sappi - Cloquet
FHRPNB	17	2703700011	Flint Hill Resources - Pine Bend
BLNPAP	18	2706100001	Blandin Paper / Rapids Energy
BOISEC	19	2707100002	Boise Cascade - International Falls
MINNTC	20	2713700005	US Steel - Minntac
MNPWHB	21	2713700015	Minnesota Power - ML Hibbard
DULSTM	22	2713700022	Duluth Steam Cooperative
GEOPAC	23	2713700031	Georgia Pacific - Duluth
HIBTAC	24	2713700061	Hibbing Taconite (All Other)
ARCELR	25	2713700062	Arcelor Mittal (All Other)
KEETAC	26	2713700063	US Steel - Keetac
UTACFP	27	2713700113	United Taconite - Fairlane Plant (All Other)
INTPAP	28	2700900011	International Paper - Sartell
MARTHN	29	2716300003	Marathon Ashland Petroleum
POTLTC	30	2713700083	Potlatch - Cook
POTLTG	31	2706100010	Potlatch - Grand Rapids
TILDEN	32	26103B4885	Tilden Mining Company (All Other)
NSMPB1	33	2707500003	Northshore Mining - Power Boiler 1
NSMPB2	34	2707500003	Northshore Mining - Power Boiler 2
NSMF11	35	2707500003	Northshore Mining - Furnace 11
NSMF12	36	2707500003	Northshore Mining - Furnace 12
UTACL1	37	2713700113	United Taconite - Line 1
UTACL2	38	2713700113	United Taconite - Line 2
ARCLN1	39	2713700062	Arcelor Mittal - Line 1
HBTCF1	40	2713700061	Hibbing Taconite - Line 1
HBTCF2	41	2713700061	Hibbing Taconite - Line 2
HBTCF3	42	2713700061	Hibbing Taconite - Line 3
TILDL1	43	26103B4885	Tilden Mining - Line 1

🟩 Included in Barr Output Evaluation

[3] Barr tracked furnace stacks and other noted stacks on a unit-basis while all other stacks were included in the "All Other" stacks

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APPENDIX D: Summary of CAM_X Elevated Point Source Emissions

March 6, 2013

Summary of CAMx Elevated Point Source Emissions

				Emissions		Emissions		Emission Reductions
				Proposed FIP		Final FIP		Baseline - Final FIP
	Emission Unit		Pollutant	Baseline		FIP		
Facility	ModID	Description		tons/yr	Note(s)	tons/yr	Note(s)	tons/yr
Hibbing Taconite Company	{3}	Line 1	NOx	2,497	[1]	749	[3]	1,748
			SO2	202	[2]	202	[4]	0
	{4}	Line 2	NOx	2,144	[1]	643	[3]	1,500
			SO2	180	[2]	180	[4]	0
	{5}	Line 3	NOx	2,247	[1]	674	[3]	1,573
			SO2	188	[2]	188	[4]	0
	HTC	BART Furnaces Combined	NOx	6,888		2,066		4,821
			SO2	570		570		0
Northshore Mining Company		Process Boiler 1/2	NOx	41	[5]	41	[8]	0
			SO2					
	{24}	Furnace 11	NOx	386	[6]	116	[9]	270
			SO2	38	[7]	38	[10]	0
	{25}	Furnace 12	NOx	378	[6]	113	[9]	264
			SO2	35	[7]	35	[10]	0
	NSM	BART Furnaces Combined	NOx	764		229		535
			SO2	73		73		0
Tilden Mining Company	{1}	Boiler #1/2	NOx	79	[11]	79	[16]	0
			SO2	0	[12]	0	[17]	0
	{3}	Ore Dryer # 1	NOx	15	[13]	15	[18]	0
			SO2	34	[13]	34	[19]	0
	{5}	Furnace #1	NOx	4,613	[14]	1,384	[20]	3,229
			SO2	1,153	[15]	231	[21]	922
	TMC	BART Furnace	NOx	4,613		1,384		3,229
			SO2	1,153		231		922
United Taconite	{26}	Line 1	NOx	**1,643**	[22][23]	493	[26]	1,150
			SO2	1,293	[25]	577	[27]	716
	{24}	Line 2	NOx	**3,687**	[22][24]	1,106	[26]	2,581
			SO2	2,750	[25]	1,392	[27]	1,357
	UTAC	BART Furnaces Combined	NOx	5,330		1,599		3,731
			SO2	4,043		1,969		2,074
Arcelor Mittal	ARC	Line 1	NOx	3,639	[28]	1,092	[30]	2,547
	{12}		SO2	179	[29]	179	[31]	0

TOTAL BART Furnaces	NOx	21,233		6,370		14,863
	SO2	6,018		3,022		2,996

🟨 Facility Furnace Unit Summary or Overall Summary
🟩 FIP Baseline does not match reference

Notes:

[1] HTC Line 1-3 - USEPA FIP NOx Baseline Emissions Proposed FIP Table V - B.24

[2] HTC Line 1-3 - USEPA FIP SO2 Baseline Emissions from Proposed FIP Table V - B.27

[3] HTC Line 1-3 - USEPA Proposed FIP NOx = 70% control from Baseline - Table V - B.24; Final FIP (1.2 or 1.5 lb/MMBTU) assumed equivalent

[4] HTC Line 1-3 - USEPA Final FIP - no additional SO2 control (Final FIP = Baseline Emissions)

[5] NSM Process Boilers 1&2 - NOx Emissions from Proposed FIP Table V - B.12 (p49318)

[6] NSM Furnace 11/12 NOx Emissions from Proposed FIP - Table V - B.8

[7] NSM Furnace 11/12 SO2 Baseline FIP Emission Rate from Proposed FIP Table V - B.10

[8] NSM Process Boilers #1 and #2 - USEPA Final BART limit of 0.085 lb NOx/MMBTU (30-day rolling average) - No additional control.

[9] NSM Furnace 11/12 - USEPA Proposed FIP NOx = 70% control from Baseline _ Table V - B.8; Final FIP (1.2 or 1.5 lb/MMBTU) assumed equivalent

[10] NSM Furnace 11/12 - no Additional SO2 Control Applied by Proposed or Final FIP (Final FIP = Baseline Emissions)

[11] Tilden Process Boilers 1 & 2 NOx Baseline Emissions Proposed FIP Table V - B.38

[12] Tilden Process Boilers 1 & 2 SO2 Baseline Emissions Proposed FIP Table V - B.37 (0.25 TPY)

[13] Tilden Dryer #1 Emissions from Proposed FIP Table V - B.39 (SO2) and Table V - B.40 (NOx) - 34.07 TPY SO2, 15.1 TPY NOx

[14] Tilden Furnace 1 NO2 Baseline - Proposed FIP Table V - B.34

[15] Tilden Furnace 1 SO2 Baseline - Proposed FIP Projected SO2 Emission Reductions - Table V-B.36; Baseline Emissions Back-calculated from 90% control

[16] Tilden Process Boilers 1 & 2 - No additional NOx control (Final FIP = Baseline Emissions)

[17] Tilden Process Boilers 1 & 2 - USEPA Final BART limit of 1.2%S in fuel - No additional SO2 control (Final FIP = Baseline Emissions)

[18] Tilden Ore Dryer #1 - No additional NOx control (Final FIP = Baseline Emissions)

[19] Tilden Ore Dryer #1 - USEPA Final BART limit of 1.5%S in fuel - No additional SO2 control (Final FIP = Baseline Emissions)

[20] Tilden Furnace 1 - USEPA Proposed FIP NOx = 70% control from Baseline _ Table V - B.34; Final FIP (1.2 or 1.5 lb/MMBTU)
NOx emissions referenced in final FIP text at 65% control from baseline (page 8721); but that is not consistent with the remaining facilities
Modeled emissions assumed 70% control to provide maximum emission reductions

[21] Tilden - USEPA Final BART restriction - Only combust natural gas in Grate Kiln Line 1 with limit computed in lb SO2/hr based on CEMs;
SO2 emissions referenced in final FIP text at 80% control from baseline (page 8721)

[22] UTAC - USEPA FIP NOx Baseline Emissions Proposed FIP Table V - B.14

[23] UTAC - Line 1 NOx Permit limit specified in permit 13700113-005 - 1,655 TPY, issued 8/19/2010, page A-49 (reference from USEPA 114 Request Question 6)

[24] UTAC - Line 2 NOx Permit limit specified in permit 13700113-005 - 3,692 TPY, issued 8/19/2010, page A-56 (reference from USEPA 114 Request Question 6)

[25] UTAC Line 1&2 - USEPA proposed FIP Baseline SO2 Emissions Table V - B.17; 90% Control in Table, 95% Control within text _ Proposed FIP (page 49319)
Modeled baseline emissions back-calculated from 90% Control; SO2 Reductions match Table V - C.13 in Proposed FIP

[26] UTAC Line 1&2 - USEAP Proposed FIP NOx = 70% Control from Baseline Table V - B.14; Final FIP (1.2 or 1.5 lb/MMBTU)
Modeled emissions assumed 70% control to provide maximum emission reductions

[27] UTAC Line 1&2 - USEPA Final BART SO2 Limit of 529 lb/hr Combined (155 lb/hr - Line 1 & 374 lb/hr - Line 2) - 30-day rolling average.
Modeled Final FIP emissions used the limits and 85% operating factor to calculate the annual emissions (designed to maximize reductions)

[28] Arcelor Line 1 - USEPA proposed FIP Baseline NOx Emissions Table V - B.19

[29] Arcelor Line 1 - USEPA proposed FIP Baseline SO2 Emissions Table V - B.21

[30] Arcelor Line 1 - Proposed FIP NOx = 70% Control from Baseline Table V - B.19; Final FIP (1.2 or 1.5 lb/MMBTU) assumed equivalent

[31] Arcelor Line 1 - USEPA Final FIP - no additional SO2 control (Final FIP = Baseline Emissions)

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APPENDIX E: Electronic Mail Requests - Proposed and Final FIP Emission Clarifications

March 6, 2013

From: Jeffry D. Bennett
Sent: Thursday, January 31, 2013 7:42 PM
To: 'Rosenthal.steven@Epa.gov'
Cc: 'Long, Michael E'
Subject: Clarification Regarding Emissions within the Final Taconite BART FIP
Attachments: EPA_FIP_Emission_Summary_01292013.xls

Steve,

Pursuant to our conversation last week regarding the baseline and controlled emission inventories within the proposed and final BART FIP for taconite furnaces, this e-mail is designed to request clarification regarding certain information contained in the rule. To that end, attached you will find a spreadsheet that summarizes and documents (to the maximum extent possible) the emission inventory data within the FIP rulemakings.

Specifically at this time, we are requesting:

(1) verification of the UTAC baseline NOx information for Line 1 and Line 2 ('Summary' Tab, Cells E30 and E32),

(2) clarification of the differences between the information contained in Columns H and I of the spreadsheet, Column H contains the difference between the FIP baseline and proposed FIP control emissions and was calculated from information within Table V-B.xx* - NOx or SO2 facility specific emission data. The Column I information contains the emission reductions obtained from Table V-C.yy visibility improvement estimate tables. For each facility, these two columns should match, but the NOx information does not. Ultimately, the bases for Table V-C.yy data is the component that is missing.

*Note: for Hibbing Taconite Line 1, a typographical error was discovered in Table V-B.24 and corrected in the spreadsheet.

(3) EPA's estimates of final FIP emissions on a tons/year basis with the corresponding emission reductions (i.e. FIP baseline – final FIP control) expected by EPA. This information would replace the "?" in Columns L and M of the spreadsheet. Along with the estimates, documentation of their bases would be extremely beneficial. For example, NOx could include either a % reduction from baseline or MMBTU/hour, Hours/year, and the appropriate lb NOx/MMBTU limit.

If you have any questions regarding these requests, feel free to contact Mike Long or myself. Thank you for your time.

Jeffry D. Bennett, PE
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From: Jeffry D. Bennett
Sent: Thursday, February 14, 2013 12:02 PM
To: 'Robinson.randall@Epa.gov'
Subject: FW: Clarification Regarding Emissions within the Final Taconite BART FIP
Attachments: EPA_FIP_Emission_Summary_01292013.xls

Randy,

I talked with Steve Rosenthal yesterday about the taconite BART FIP emissions (see e-mail below). He told me that you “wrote the section on visibility improvement” and suggested I contact you about item 2 and a portion of the information requested in item 3. Barr Engineering is contracted with Cliffs Natural Resources and Arcelor Mittal to provide their taconite facilities with technical support regarding the FIP. At this point, we are trying to summarize and document the bases for the SO2 and NOx emissions that were used in the EPA baseline, the proposed FIP, and the final FIP for all their facilities.

The attached spreadsheet that I sent Steve previously includes the summary. Item 2 is related to differences between the NOx emission reductions used in the ratio visibility improvement calculations in the proposed FIP (Table V – C.yy) and the emission reductions in Table V – B.xx for each facility. Steve thought you would have the information about the basis for the Table V – C.yy reductions.

Item 3 is requesting information about the final FIP emission reductions. Specifically, you would probably have information regarding the emissions for Tilden Mining and United Taconite (UTAC) from the CALPUFF modeling completed by Trent Wickman referenced in the final FIP rulemaking docket. Please give me a call to discuss this at your earliest convenience. We are attempting to finalize the summary by COB tomorrow. Thanks for any help you can provide.

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APPENDIX F: CAMx Modeling Results by Facility

March 6, 2013

Arcelor Mittal CAMx Emissions and Modeling Results

Arcelor Emissions

Unit	EPA FIP Baseline NOx Emission (TPY) [1]	Final FIP NOx Emission (TPY) [1]	NOx Emission Difference (TPY)	EPA FIP Baseline SO2 Emission (TPY) [2]	Final FIP SO2 Emission (TPY)[3]	SO2 Emission Difference (TPY)
Line 1	3,639	1,092	2,547	179	179	0
TOTAL	**3,639**	**1,092**	**2,547**	**179**	**179**	**0**

[1] FIP Baseline and Control NOx Emissions from EPA Proposed FIP Table V-B.19 – Projected Annual NOx Emission Reductions [TPY].

[2] FIP Baseline SO2 Emissions are from EPA Proposed FIP Table V-B.21 – Annual SO2 Emissions [TPY]

[3] No SO2 emission reductions in Final FIP (i.e. EPA Baseline = Final FIP control)

Arcelor CAMx Results (By Unit) [4]

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Proposed FIP Days > 0.5 dV	Proposed FIP 98% dV	Difference Days >0.5 dV [5]	Difference 98% dV [5]
Boundary Waters						
2002						
Line #1	30	0.789	18	0.713	12	0.076
Facility Total	43	0.99	35	0.96	8	0.03
2005						
Line #1	7	0.491	3	0.326	4	0.165
Facility Total	19	0.74	8	0.55	11	0.19
Voyageurs						
2002						
Line #1	1	0.287	0	0.202	1	0.085
Facility Total	1	0.34	0	0.22	1	0.12
2005						
Line #1	0	0.182	0	0.122	0	0.060
Facility Total	0	0.22	0	0.16	0	0.06
Isle Royale						
2002						
Line #1	0	0.075	0	0.053	0	0.022
Facility Total	0	0.09	0	0.06	0	0.03
2005						
Line #1	0	0.049	0	0.033	0	0.016
Facility Total	0	0.06	0	0.04	0	0.02

[4] Visibility benchmarks:

0.5 dV impact is the BART eligibility threshold (i.e. if a facility has less than 0.5 dV impact in the baseline, no BART is required),
1.0 dV difference is the presumed human perceptible level for visibility improvement, and
0.1 dV difference was defined by other agencies as the degree of visibility improvement that is too low to justify additional emission controls. Also, EPA's Regional Haze Rule mentions that "no degradation" to visibility would be "defined as less than a 0.1 deciview increase."

[5] These two columns provide the difference in predicted days >0.5 dV and 98th percentile visibility improvement from the baseline to the FIP control emissions. The annual average number of days with > 0.5 dV improvement at all the Class I areas is considerably less than EPA's estimate (11 to 53). Also, the averages of the 98th percentile differences are **10 to 37 times less** than the predicted improvement by EPA. Note: the table below formed the basis for EPA's inclusion of control necessary at Arcelor Mittal.

Arcelor Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

(EPA Table C Emission Difference = 2,859 TPY NOx)[6]
(EPA Table B Emission Difference = 2,547 TPY NOx)[7]

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV[8]	CAMx Modeled Difference 98% dV
Boundary Waters	24	1.7		10	0.11
Voyageurs	11	0.9		1	0.09
Isle Royale	18	1.1		0	0.03

[6] Emission Difference Obtained from EPA Proposed FIP Table V-C.10 – Estimated Emission Reductions and Resulting Changes in Visibility Factors for Arcelor Mittal.

[7] Emission Difference Obtained from EPA Proposed FIP Table V-B.19.

[8] The number of days with visibility >0.5 deciviews (dV) can be a misleading indicator as illustrated by the Arcelor Mittal and Northshore Mining results (below). The 98th percentile visibility improvement at Boundary Waters during the 2002 modeled year was 0.03 dV. However, the modeling predicts this insignificant change will result in eight more days of "good visibility", defined as days with visibility at or below the 0.5 deciview threshold. Further, the Northshore Mining results at Isle Royale indicate a miniscule 0.01 deciviews, or one hundred times less than a perceptible improvement to visibility. Nonetheless, the modeling predicts this insignificant change will result in two more days of "good visibility". In both circumstances, this does not mean that the visibility change was discernible. The model gives credit for an improved day when the predicted impairment falls from 0.51 to 0.50 deciviews, but that improvement is illusory because at 0.51 deciviews people do not perceive a regional haze problem. The difference in visibility from natural background when evaluating the baseline could have several days near the 0.5 dV "contribute to visibility degradation" threshold, but well less than the 1 dV "cause visibility degradation" threshold. Then, a very small change in visibility from the baseline to the controlled emission scenario (~0.01 – 0.1 dV) could cause a large number of days to be less than the 0.5 dV benchmark without producing any real benefit to visibility.

Hibbing Taconite (HibTac) CAMx Emissions and Modeling Results

HibTac Emissions

Unit	EPA FIP Baseline NOx Emission (TPY)	Final FIP NOx Emission (TPY)	NOx Emission Difference (TPY)	EPA FIP Baseline SO2 Emission (TPY)	Final FIP SO2 Emission (TPY)	SO2 Emission Difference (TPY)
Line 1	2,497	749	1,748	202	202	0
Line 2	2,144	643	1,500	180	180	0
Line 3	2,247	674	1,573	188	188	0
TOTAL	**6,888**	**2,066**	**4,822**	**570**	**570**	**0**

HibTac CAMx Results (By Unit)

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
2002						
Line 1	1	0.337	1	0.305	0	0.032
Line 2	2	0.287	0	0.260	2	0.027
Line 3	1	0.318	0	0.245	2	0.073
Facility Total	33	1.10	22	0.96	11	0.14
2005						
Line 1	0	0.217	0	0.158	0	0.057
Line 2	0	0.203	0	0.124	0	0.079
Line 3	0	0.223	0	0.140	0	0.083
Facility Total	14	0.85	11	0.62	3	0.23
Voyageurs						
2002						
Line 1	0	0.197	0	0.168	0	0.029
Line 2	0	0.197	0	0.159	0	0.038
Line 3	0	0.211	0	0.163	0	0.048
Facility Total	18	0.67	10	0.61	8	0.06
2005						
Line 1	0	0.126	0	0.102	0	0.024
Line 2	0	0.122	0	0.085	0	0.037
Line 3	0	0.133	0	0.103	0	0.030
Facility Total	8	0.51	5	0.36	3	0.15

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Isle Royale						
2002						
Line 1	0	0.053	0	0.047	0	0.006
Line 2	0	0.045	0	0.036	0	0.009
Line 3	0	0.046	0	0.037	0	0.009
Facility Total	0	0.16	0	0.13	0	0.03
2005						
Line 1	0	0.038	0	0.027	0	0.011
Line 2	0	0.034	0	0.022	0	0.012
Line 3	0	0.037	0	0.026	0	0.011
Facility Total	0	0.13	0	0.09	0	0.04

HibTac Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

(EPA Table C Emission Difference = 5,259 TPY NOx)[8]

(EPA Table B Emission Difference = 4,822 TPY NOx)[9]

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 98% dV
Boundary Waters	44	3.2		7	0.19
Voyageurs	21	1.7		5	0.11
Isle Royale	26	2.1		0	0.04

[8] Emission Difference Obtained from EPA Proposed FIP Table V-C.11 – Estimated Emission Reductions and Resulting Changes in Visibility Factors for Hibbing Taconite.

[9] Emission Difference Obtained from EPA Proposed FIP Table V-B.24.

Northshore Mining CAMx Emissions and Modeling Results

Northshore Emissions

Unit	EPA FIP Baseline NOx Emission (TPY)	Final FIP NOx Emission (TPY)	NOx Emission Difference (TPY)	EPA FIP Baseline SO2 Emission (TPY)	Final FIP SO2 Emission (TPY)	SO2 Emission Difference (TPY)
Power Boiler #1	676	676	0	681	681	0
Power Boiler #2	1,093	1,093	0	1,098	1,098	0
Furnace 11	386	116	270	38	38	0
Furnace 12	378	113	265	35	35	0
FURNACES	**764**	**229**	**535**	**73**	**73**	**0**
TOTAL	**2,533**	**1,998**	**535**	**1,852**	**1,852**	**0**

Northshore CAMx Results (By Unit)

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
2002						
Power Boiler #1	32	1.487	32	1.499	0	-0.012
Power Boiler #2	49	2.087	49	2.097	0	-0.010
Furnace 11	0	0.136	0	0.139	0	-0.003
Furnace 12	0	0.133	0	0.122	0	0.011
Facility Total	73	4.16	72	4.14	1	0.02
2005						
Power Boiler #1	13	0.640	13	0.654	0	-0.014
Power Boiler #2	22	0.926	23	0.911	0	0.015
Furnace 11	0	0.087	0	0.067	0	0.020
Furnace 12	0	0.082	0	0.076	0	0.006
Facility Total	51	1.67	50	1.68	1	-0.01
Voyageurs						
2002						
Power Boiler #1	1	0.196	1	0.196	0	0.000
Power Boiler #2	1	0.293	1	0.293	0	0.000
Furnace 11	0	0.016	0	0.013	0	0.003
Furnace 12	0	0.015	0	0.013	0	0.002
Facility Total	8	0.51	8	0.51	0	0.00

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Voyageurs						
2005						
Power Boiler #1	0	0.188	0	0.193	0	-0.005
Power Boiler #2	1	0.244	1	0.247	0	-0.003
Furnace 11	0	0.020	0	0.018	0	0.002
Furnace 12	0	0.021	0	0.016	0	0.004
Facility Total	6	0.47	6	0.46	0	0.01
Isle Royale						
2002						
Power Boiler #1	3	0.294	3	0.294	0	0.000
Power Boiler #2	6	0.412	6	0.408	0	0.004
Furnace 11	0	0.034	0	0.028	0	0.006
Furnace 12	0	0.037	0	0.029	0	0.008
Facility Total	16	0.75	15	0.74	1	0.00
2005						
Power Boiler #1	3	0.180	3	0.180	0	0.000
Power Boiler #2	4	0.320	4	0.322	0	-0.002
Furnace 11	0	0.036	0	0.023	0	0.013
Furnace 12	0	0.034	0	0.022	0	0.012
Facility Total	10	0.57	8	0.55	2	0.02

Northshore Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

(EPA Table C Emission Difference = 926 TPY NOx)[10]

(EPA Table B Emission Difference = 535 TPY NOx)[11]

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 98% dV
Boundary Waters	8	0.6		1	0.01
Voyageurs	4	0.3		0	0.01
Isle Royale	5	0.4		2	0.01

[10] Emission Difference Obtained from EPA Proposed FIP Table V-C.12 – Estimated Emission Reductions and Resulting Changes in Visibility Factors for Northshore Mining.

[11] Emission Difference Obtained from EPA Proposed FIP Table V-B.8; further the emission reductions in Table C exceed the FIP baseline in Table B by 142 TPY.

United Taconite (UTAC) CAMx Emissions and Modeling Results

UTAC Emissions

Unit	EPA FIP Baseline NOx Emission (TPY)	Final FIP NOx Emission (TPY)	NOx Emission Difference (TPY)[12]	EPA FIP Baseline SO2 Emission (TPY)	Final FIP SO2 Emission (TPY)[13]	SO2 Emission Difference (TPY)
Line 1	1,643	493	1,150	1,293	577	716
Line 2	3,687	1,106	2,581	2,750	1,392	1,358
TOTAL	**5,330**	**1,599**	**3,731**	**4,043**	**1,969**	**2,074**

[12]NOx emission difference was calculated using 70% emission reduction from EPA Baseline within the proposed FIP (corresponding to 1.2 lb NOx/MMBTU); to ensure maximum emission reductions were evaluated there was no change to the final FIP emissions to reflect the final FIP limit of 1.5 lb NOx/MMBTU.

[13]Final FIP SO2 Emissions were calculated using the final FIP limit of 529 lb/hr with an operating factor of 85%; this was done to maximize the emission reductions while using a reasonable operating factor

UTAC CAMx Results (By Unit)

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
2002						
Line #1	22	1.294	10	0.674	12	0.620
Line #2	45	2.744	30	1.556	15	1.189
Facility Total	76	4.22	55	2.37	21	1.85
2005						
Line #1	11	0.610	2	0.303	9	0.307
Line #2	26	1.294	15	0.678	11	0.616
Facility Total	52	2.52	34	1.57	18	0.95
Voyageurs						
2002						
Line #1	12	0.606	2	0.307	10	0.299
Line #2	26	1.452	15	0.771	11	0.681
Facility Total	42	2.10	26	1.11	16	0.99
2005						
Line #1	4	0.331	1	0.181	3	0.150
Line #2	17	0.786	6	0.446	11	0.340
Facility Total	33	1.47	14	0.76	19	0.71

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Isle Royale						
2002						
Line #1	0	0.255	0	0.117	0	0.138
Line #2	8	0.518	0	0.266	8	0.252
Facility Total	13	0.81	3	0.41	10	0.40
2005						
Line #1	0	0.163	0	0.080	0	0.083
Line #2	1	0.322	0	0.184	1	0.138
Facility Total	10	0.57	0	0.28	10	0.29

UTAC Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

(EPA Table C Emission Difference = 3,208 TPY NOx and 3,639 TPY SO2)[14]

(EPA Table B Emission Difference = 3,731 TPY NOx and 3,639 TPY SO2)[15]

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV[16]	CAMx Modeled Difference 98% dV[16]
Boundary Waters	29	1.9		20	1.40
Voyageurs	12	0.99		18	0.85
Isle Royale	14	1.16		10	0.35

[14] Emission Difference Obtained from EPA Proposed FIP Table V-C.13 – Estimated Emission Reductions and Resulting Changes in Visibility Factors for United Taconite.

[15] Emission Difference Obtained from EPA Proposed FIP Table V-B.14 (SO2) and V-B.17 (NOx) – NOx reductions are not consistent

[16] Baseline – final FIP Emission Reductions -> 3,731 TPY NOx and 2,074 TPY SO2

The United Taconite comparison table above does not provide an "apples to apples" comparison. As noted, the EPA estimated visibility benefits include more SO2 emission reductions (proposed FIP) than are included in the final FIP. This table was amended to include the revised SO2 emission reductions using EPA's apparent methodology within the proposed FIP. The EPA scalars (proposed FIP – Table V – C.9) were applied for each pollutant using the corrected emission reduction for NOx and the revised emission reduction for SO2. Then, those resultants were averaged for each of the Class I areas to obtain the amended EPA estimates below to provide for the appropriate comparison of EPA's method.

Amended UTAC Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

Final FIP Emission Difference = 3,731 TPY NOx and 2,074 TPY SO2

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 98% dV
Boundary Waters	22	1.6		20	1.40
Voyageurs	10	0.8		18	0.85
Isle Royale	14	1.1		10	0.35

As discussed above, the SO4 and NO3 visibility benefits were combined by EPA. The following tables provide a modeled comparison of the impacts sorted by SO4 and NO3 on a line-specific basis, then combined for both lines. The sulfate impact was derived by sorting the visibility impacts at each receptor from each scenario by maximum sulfate contribution for each line. Likewise, the nitrate impact was derived by sorting the visibility impacts at each receptor from each scenario by maximum nitrate contribution for each line. Then, the results were summed for both lines to obtain the overall UTAC impact by pollutant. In nearly all circumstances, this will overestimate the impact of the NO_X control. This is due to the impact from the sulfate reductions that drives the total visibility impact with a much smaller percentage from the nitrate reductions. When the nitrate impact is maximized by the sorting technique, the overall impact on the same day could be very small (e.g. nitrate = 0.15 dV; total = 0.20 dV) and would not show up as part of the overall visibility change (see Line 2 – 2002 Boundary Waters results).

UTAC Line 1 – Pollutant Specific Modeling Results

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
2002						
Line #1 – NO3	0	0.106	0	0.059	0	0.047
Line #1 – SO4	22	1.294	10	0.674	12	0.620
Line #1 – All	22	1.294	10	0.674	12	0.620
2005						
Line #1 – NO3	0	0.136	0	0.083	0	0.053
Line #1 – SO4	8	0.571	2	0.280	6	0.291
Line #1 – All	11	0.610	2	0.303	9	0.307
Voyageurs						
2002						
Line #1 – NO3	0	0.040	0	0.017	0	0.023
Line #1 – SO4	11	0.582	2	0.301	9	0.281
Line #1 – All	12	0.606	2	0.307	10	0.299
2005						
Line #1 – NO3	0	0.048	0	0.027	0	0.021
Line #1 – SO4	4	0.330	1	0.155	3	0.175
Line #1 – All	4	0.331	1	0.181	3	0.150
Isle Royale						
2002						
Line #1 – NO3	0	0.033	0	0.015	0	0.018
Line #1 – SO4	0	0.216	0	0.104	0	0.112
Line #1 – All	0	0.255	0	0.117	0	0.138
2005						
Line #1 – NO3	0	0.026	0	0.011	0	0.015
Line #1 – SO4	0	0.150	0	0.072	0	0.078
Line #1 – All	0	0.163	0	0.080	0	0.083

UTAC Line 2 – Pollutant Specific Modeling Results

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
2002						
Line #2 – NO3	1	0.237	0	0.090	1	0.147
Line #2 – SO4	44	2.679	28	1.547	16	1.132
Line #2 – All	45	2.744	30	1.556	15	1.189
2005						
Line #2 – NO3	1	0.195	0	0.091	1	0.104
Line #2 – SO4	25	1.196	15	0.659	10	0.539
Line #2 – All	26	1.294	15	0.678	11	0.616
Voyageurs						
2002						
Line #2 – NO3	0	0.104	0	0.031	0	0.073
Line #2 – SO4	25	1.446	15	0.768	10	0.678
Line #2 – All	26	1.452	15	0.771	11	0.681
2005						
Line #2 – NO3	0	0.083	0	0.033	0	0.050
Line #2 – SO4	16	0.773	6	0.436	10	0.337
Line #2 – All	17	0.786	6	0.446	11	0.340
Isle Royale						
2002						
Line #2 – NO3	0	0.054	0	0.018	0	0.036
Line #2 – SO4	7	0.469	0	0.245	7	0.224
Line #2 – All	8	0.518	0	0.266	8	0.252
2005						
Line #2 – NO3	0	0.046	0	0.016	0	0.030
Line #2 – SO4	1	0.319	0	0.166	1	0.153
Line #2 – All	1	0.322	0	0.184	1	0.138

UTAC Comparison of Sulfate-Specific Amended EPA Final FIP Visibility Improvement Estimates with CAMx Modeling Analyses

Final FIP Emission Difference = 2,074 TPY SO2

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 98% dV
Boundary Waters	14	1.0		22	1.29
Voyageurs	6	0.5		16	0.74
Isle Royale	8	0.6		4	0.28

UTAC Comparison of Nitrate-Specific Amended EPA Final FIP Visibility Improvement Estimates with CAMx Modeling Analyses

Final FIP Emission Difference = 3,731 TPY NOx

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 98% dV
Boundary Waters	31	2.3		1	0.18
Voyageurs	15	1.1		0	0.08
Isle Royale	20	1.6		0	0.05

The maximum 98th percentile NO3 impact when combining both line emission reductions is 0.18 dV, while the maximum 98th percentile SO4 impact for both lines is 1.29 dV. Based on these results, it is evident that the SO4 impact on the Class I areas provides the vast majority of the predicted CAMx estimates of visibility improvement. This finding is consistent with MPCA's original finding for BART in the 2009 SIP that NOx emission reductions do not provide substantive visibility improvement.

Tilden Mining CAMx Emissions and Modeling Results

Tilden Emissions

Unit	EPA FIP Baseline NOx Emission (TPY)	Final FIP NOx Emission (TPY)	NOx Emission Difference (TPY)	EPA FIP Baseline SO2 Emission (TPY)	Final FIP SO2 Emission (TPY)	SO2 Emission Difference (TPY)
Line 1	4,613	1,384	3,229	1,153	231	922
TOTAL	**4,613**	**1,384**	**3,229**	**1,153**	**231**	**922**

Tilden CAMx Results (By Unit)

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
2002						
Line #1	0	0.141	0	0.037	0	0.104
2005						
Line #1	0	0.097	0	0.042	0	0.055
Voyageurs						
2002						
Line #1	0	0.042	0	0.011	0	0.031
2005						
Line #1	0	0.041	0	0.010	0	0.031
Isle Royale						
2002						
Line #1	1	0.300	0	0.094	1	0.206
2005						
Line #1	0	0.211	0	0.070	0	0.141

Tilden Line 1 – Pollutant Specific Modeling Results

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
2002						
Line #1 – NO3	0	0.031	0	0.013	0	0.018
Line #1 – SO4	0	0.102	0	0.022	0	0.080
Line #1 – All	0	0.141	0	0.037	0	0.104
2005						
Line #1 – NO3	0	0.045	0	0.042	0	0.003
Line #1 – SO4	0	0.087	0	0.019	0	0.068
Line #1 – All	0	0.097	0	0.042	0	0.055
Voyageurs						
2002						
Line #1 – NO3	0	0.002	0	0.001	0	0.001
Line #1 – SO4	0	0.041	0	0.011	0	0.030
Line #1 – All	0	0.042	0	0.011	0	0.031
2005						
Line #1 – NO3	0	0.005	0	0.003	0	0.002
Line #1 – SO4	0	0.039	0	0.008	0	0.031
Line #1 – All	0	0.041	0	0.010	0	0.031
Isle Royale						
2002						
Line #1 – NO3	0	0.084	0	0.038	0	0.046
Line #1 – SO4	1	0.197	0	0.052	1	0.145
Line #1 – All	1	0.300	0	0.094	1	0.206
2005						
Line #1 – NO3	0	0.043	0	0.047	0	-0.004
Line #1 – SO4	0	0.176	0	0.040	0	0.136
Line #1 – All	0	0.211	0	0.070	0	0.141

Attachment 3

2012 AECOM Report

AECOM

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

Robert Paine and David Heinold, AECOM

September 28, 2012

Executive Summary

This report reviews several aspects of the visibility assessment that is part of any Best Available Retrofit Technology (BART) assessment. The crux of this analysis focuses upon two opportunistic emission reductions that have resulted in no perceptible visibility benefits, while a straightforward application of EPA's modeling procedures would predict a substantial visibility benefit. These actual emission reduction cases include the shutdown of the Mohave Generating Station (and minimal visibility effects at the Grand Canyon) as well as the economic slowdown that affected emissions from the taconite plants in Minnesota in 2009.

There are several reasons why there is an inconsistency between the real world and the modeling results:

- Natural background conditions, which are used in the calculation of haze impacts due to anthropogenic emissions, are mischaracterized as too clean, which exaggerates the impact of emission sources. Overly clean natural conditions can erroneously indicate that some states are missing the 2018 milestone for achieving progress toward an impossible goal by the year 2064.

- The chemistry in the current EPA-approved version of CALPUFF as well as regional photochemical models overestimates winter nitrate haze, especially with the use of high ammonia background concentrations. There are other CALPUFF features that result in overpredictions of all pollutant concentrations that are detailed in this report. Therefore, BART emission reductions will be credited with visibility modeling for more visibility improvements than will really occur. We recommend that EPA adopt CALPUFF v. 6.42, which includes substantial improvements in the chemistry formulation. We also recommend the use of seasonally varying ammonia background concentrations, in line with observations and the current capabilities of CALPUFF.

- In addition to CALPUFF, the use of regional photochemical models results in significant nitrate haze overpredictions for Minnesota Class I area predictions.

- The modeled base case modeled scenario is always a worst-case emission rate which is assumed to occur every day. The actual emissions are often lower, and so the modeled improvement is an overestimate.

Impacts of the taconite plants' NO_X emissions are confined to winter months by the unique chemistry for nitrate particle formation. During these months, the attendance at the parks is greatly reduced by the closure of significant portions of the parks and the inability to conduct boating activities on frozen water bodies. In the case of Isle Royale National Park, there is total closure in the winter, lasting for 5 ½ months. The BART rule makes a provision for the consideration of such seasonal impacts. The imposition of NO_X controls year-round would not only have minimal benefits in the peak visitation season of summer, but also could lead to increases in haze due to the increased power requirements (and associated emissions) needed for their operation, an effect that has not been considered in the visibility modeling.

An analysis of the impact of the visibility impacts of Minnesota BART sources on Michigan's Class I areas, as well as the impacts of Michigan sources on Minnesota's Class I areas indicates that the effects on the other state's Class I areas is minor. The taconite plant emissions are not expected to interfere with the ability of other states to achieve their required progress under the Regional Haze Rule.

Introduction

Best Available Retrofit Technology (BART) is part of the Clean Air Act (Appendix Y of 40 CFR Part 51) as a requirement related to visibility and the 1999 Regional Haze Rule (RHR)[1] that applies to existing stationary sources. Sources eligible for BART were those from 26 source categories with a potential to emit over 250 tons per year of any air pollutant, and that were placed into operation between August 1962 and August 1977. Final BART implementation guidance for regional haze was published in the Federal Register on July 6, 2005[2].

The United States Environmental Protection Agency (EPA) has issued a proposed rule[3] to address BART requirements for taconite plants in Minnesota and Michigan that involves emission controls for SO_2 and NO_X. This document addresses the likely visibility impact of taconite plant emissions, specifically NO_X emissions, for impacts at Prevention of Significant Deterioration (PSD) Class I areas that the RHR addresses.

Locations of Emission Sources and PSD Class I Areas

Figure 1 shows the location of BART-eligible taconite plants in Minnesota and Michigan addressed in EPA's proposed rule, as well as Class I areas within 500 km of these sources. In most applications of EPA's preferred dispersion model for visibility impacts, CALPUFF[4], the distance limitation is 200-300 km because of the overprediction tendencies[5] for further distances. The overprediction occurs because of extended travel times that often involve at least a full day, during which there can be significant wind shear influences on plume spreading that the model and the meteorological wind field does not accommodate. With larger travel distances, there are higher uncertainties in the predictions of any model, either CALPUFF or a regional photochemical model. Therefore, a reasonable upper limit for establishing the impact of the taconite sources would be 500 km, with questionable results beyond 200-300 km from the source. In this case, the Class I areas involved are those shown in Figure 1. All other PSD Class I areas are much further away. It is noteworthy that EPA's visibility improvement assessment considered only three Class I areas: Voyageurs National Park, Boundary Waters Canoe Area Wilderness, and Isle Royale National Park.

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[1] Regional Haze Regulations; Final Rule. *Federal Register*, *64*, 35713-35774. (July 1, 1999).

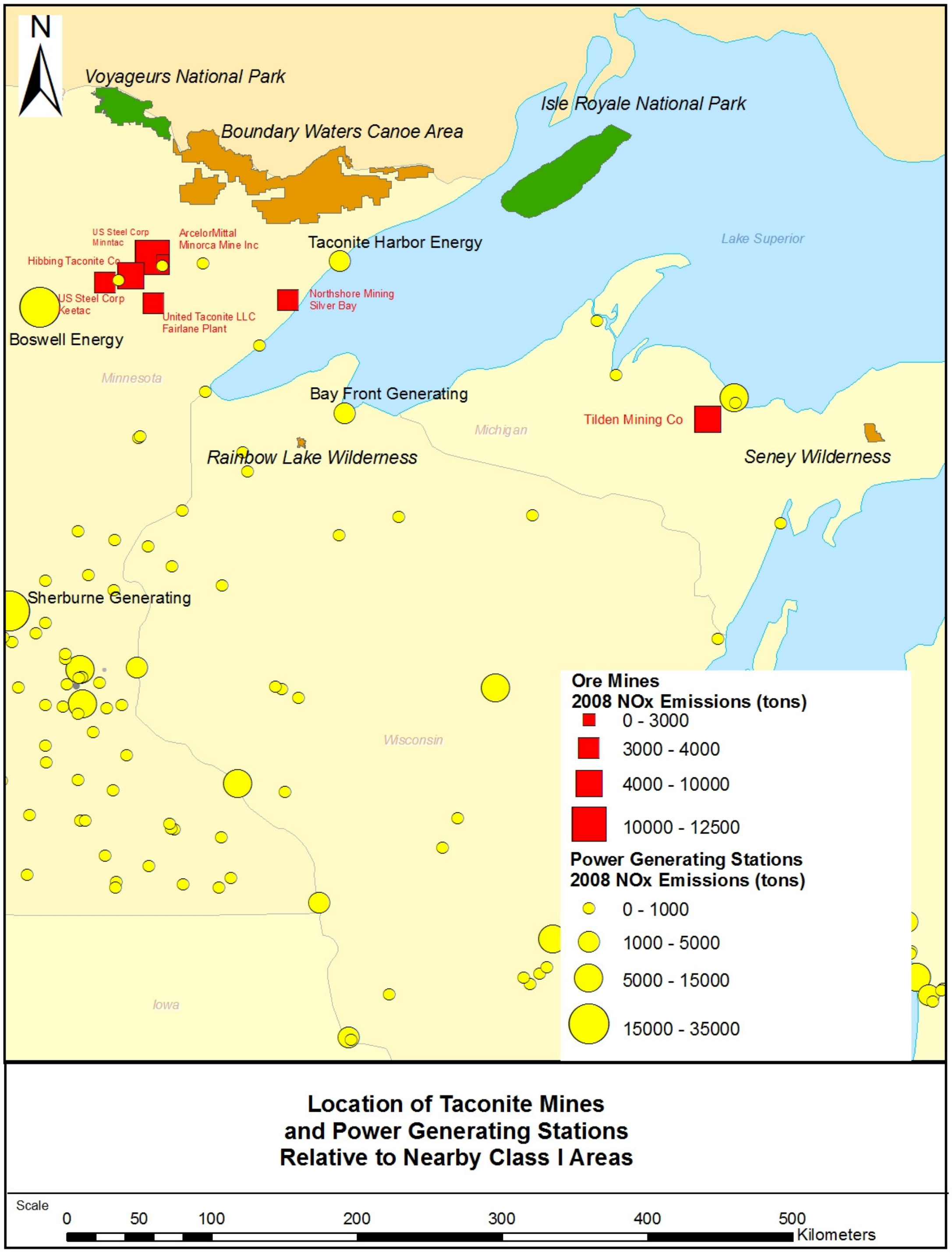
[2] Federal Register. EPA Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule. Federal Register, Vol. 70. (July 6, 2005)

[3] 77FR49308, August 15, 2012.

[4] CALPUFF Dispersion Model, 2000. http://www.epa.gov/scram001 (under 7th Modeling Conference link to Earth Tech web site).

[5] As documented in Appendix D of the IWAQM Phase 2 document, available at www.epa.gov/scram001/7thconf/calpuff/**phase2**.pdf.

Figure 1 Location of Emission Sources Relative To PSD Class I Areas in Minnesota and Michigan



Overprediction Tendency of Visibility Assessment Modeling for BART Emission Reductions

A particularly challenging part of the BART process is the lack of well-defined criteria for determining whether a proposed emission reduction is sufficient, because the criteria for determining BART are somewhat subjective in several aspects, such as what controls are cost-effective and the degree to which the related modeled reductions in haze are sufficient. In addition, the calculations of the visibility improvements, which are intrinsic to establishing the required BART controls, are subject to considerable uncertainty due both to the inherent uncertainty in model predictions and model input parameters. Alternative approaches for applying for technical options and chemistry algorithms in the United States Environmental Protection Agency's (EPA's) preferred CALPUFF model can result in a large range in the modeled visibility improvement. The degree of uncertainty is especially large when NO_X emission controls are considered as a BART option because modeling secondary formation of ammonium nitrate is quite challenging. Accurately modeling the effects of NO_X controls on visibility is very important because they are often very expensive to install and operate. As a collateral effect that needs to be taken into account for BART decisions, such controls can also complicate energy efficiency objectives and strategies to control greenhouse gases and other pollutants. In this paper we discuss why EPA's preferred application of CALPUFF would likely overestimate the predicted visibility impact of emissions, especially NO_X, and the associated effectiveness of NO_X emission controls. Overestimates of the benefits of emissions reduction are evident from the following observations, which are discussed in this document:

- Natural background extinction used in CALPOST to calculate a source's haze impacts is underestimated, which has the effect of exaggerating the impact, which is computed relative to these defined conditions. Natural conditions also dictate how well each state is adhering to the 2018 milestone for achieving progress toward this goal by the year 2064. If the specification of natural conditions is underestimated to the extent that it is not attainable regardless of contributions from U.S. anthropogenic sources, then some states will be penalized for not achieving sufficient progress toward an impossible goal. Appendix A discusses this point in more detail.

- The chemistry in the current EPA-approved version of CALPUFF overestimates winter nitrate haze, especially in conjunction with the specification of high ammonia background concentrations. This conservatism is exacerbated by CALPUFF features that result in overpredictions of all pollutant concentrations. Therefore, CALPUFF modeling will credit BART emission reductions with more visibility improvements than will really occur.

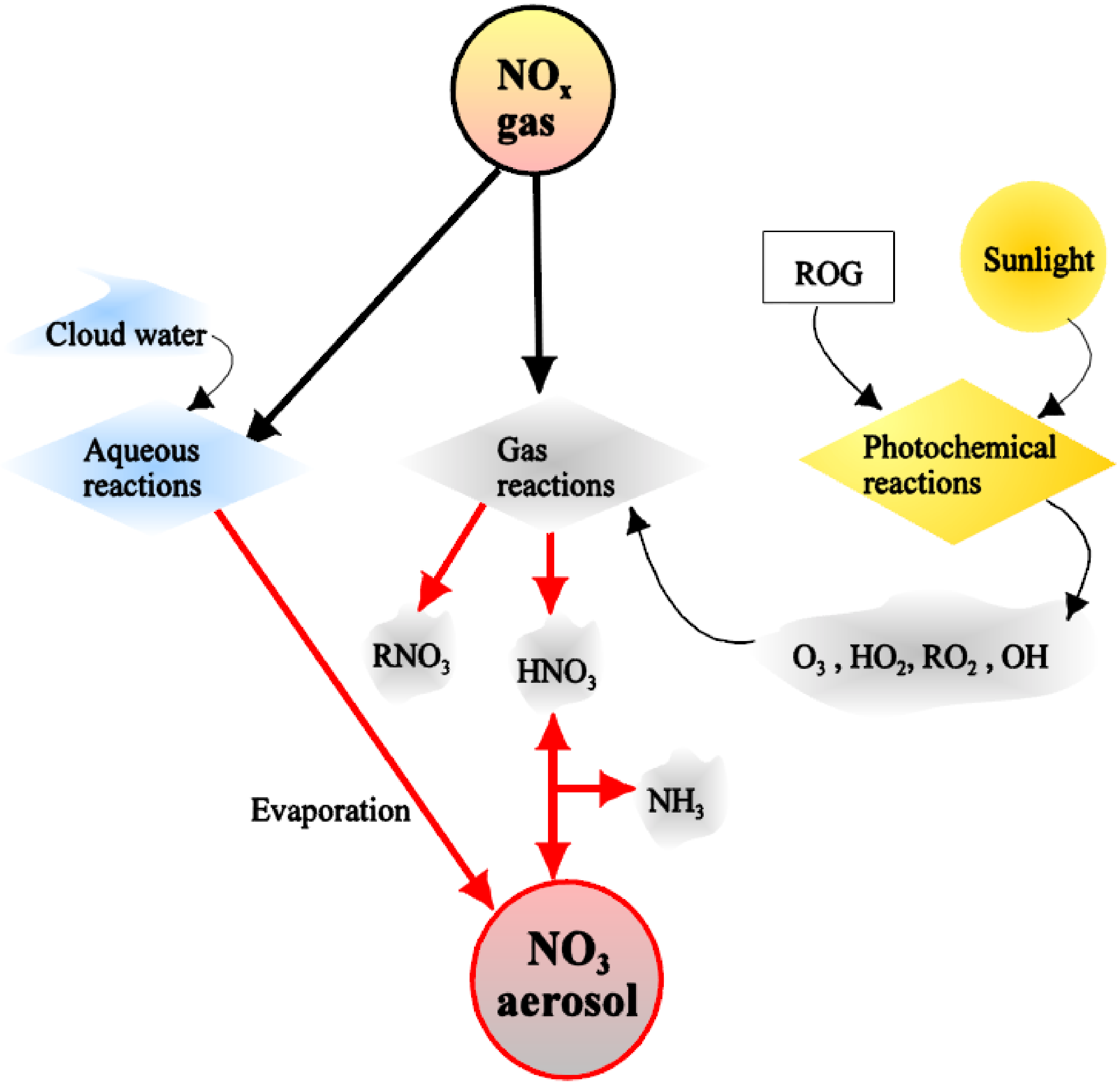
- There are examples where actual significant emission reductions have occurred, where CALPUFF modeling as conducted for BART would predict significant visibility improvements, but no perceptive changes in haze occurred.

Visibility Impact of NO_X Emissions – Unique Aspects and Seasonality

The oxidation of NO_X to total nitrate (TNO_3) depends on the NO_X concentration, ambient ozone concentration, and atmospheric stability. Some of the TNO_3 is then combined with available ammonia in the atmosphere to form ammonium nitrate aerosol in an equilibrium state with HNO_3 gas that is a function

of temperature, relative humidity, and ambient ammonia concentration, as shown in Figure 2[6]. It is important to realize that both CALPUFF and regional photochemical models tend to overpredict nitrate formation, especially in winter. A more detailed discussion of this issue is provided in Appendix B.

Figure 2 CALPUFF II NO_x Oxidation



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[6] Figure 2-32 from CALPUFF Users Guide, available at http://www.src.com/calpuff/download/CALPUFF_UsersGuide.pdf.

In CALPUFF, total nitrate ($TNO_3 = HNO_3 + NO_3$) is partitioned into each species according to the equilibrium relationship between gaseous HNO_3 and NO_3 aerosol. This equilibrium is a function of ambient temperature and relative humidity. Moreover, the formation of nitrate strongly depends on availability of NH_3 to form ammonium nitrate. A summary of the conditions affecting nitrate formation is provided below:

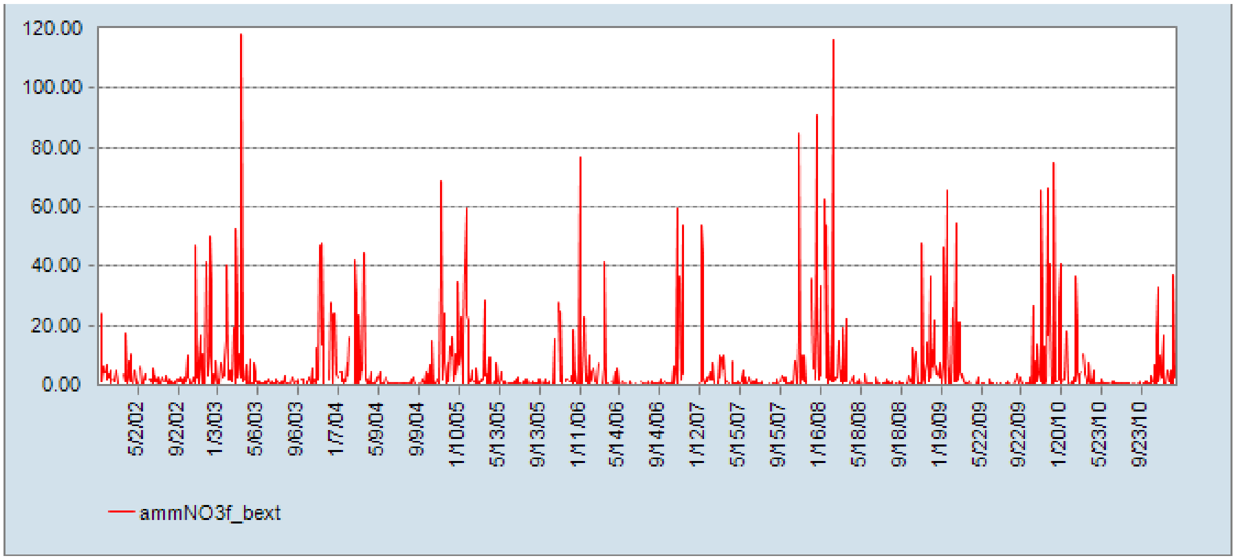
- Colder temperature and higher relative humidity create favorable conditions to form nitrate particulate matter, and therefore more ammonium nitrate is formed;
- Warm temperatures and lower relative humidity create less favorable conditions to form nitrate particulate matter, and therefore less ammonium nitrate is formed;
- Sulfate preferentially scavenges ammonia over nitrates.

For this BART analysis, the effects of temperature and background ammonia concentrations on the nitrate formation are the key to understanding the effects of various NO_X control options. For parts of the country where sulfate concentrations are relatively high and ammonia emissions are quite low, the atmosphere is likely to be in an ammonia-limited regime relative to nitrate formation. Therefore, NO_X emission controls are not very effective in improving regional haze, especially if there is very little ambient ammonia available.

In many cases, the BART visibility assessments ignore the haze increases that occur due to the additional power generation required to operate the control equipment. For NO_X controls, for example, the warm season emissions have minimal visibility impact, but the associated SO_2 emissions from the power generation required to run the controls will increase sulfate haze. These effects have not been considered in the visibility assessment modeling.

It is evident from haze composition plots available from Interagency Monitoring of Protected Visual Environments (IMPROVE) monitors that nitrate haze is confined to winter months. This is clearly shown in Figure 3, which is a timeline of nitrate haze extinction from Boundary Waters Canoe Area Wilderness. Similar patterns are evident for the other Class I areas plotted in Figure 1. The impact of NO_X emissions during the non-winter months (e.g., April through October) is very low.

Figure 3 Boundary Water Canoe Area Wilderness Ammonium Nitrate Extinction, 2002-2010



The occurrence of significant nitrate haze only in the winter months has implications for the effectiveness of haze reductions relative to park attendance. The BART Rule addresses the seasonal issue as follows: “Other ways that visibility improvement may be assessed to inform the control decisions would be to examine distributions of the daily impacts, determine if the time of year is important (e.g., high impacts are occurring during tourist season) . . .“

In this case, the high nitrate impacts are not occurring during the tourist season, especially for the water-dominant Class I areas in Minnesota (Voyageurs and Boundary Waters) that freeze in winter. In fact, for Voyageurs National Park, the typical monthly attendance[7] for an off-season month (November) is only 0.2% that of a peak-season month (July). This is obviously due in part to the brutal winter weather in northern Minnesota (and Michigan) and the lack of boating access to frozen water bodies.

Operations at the Michigan Class I areas in winter are even more restricted. Isle Royale National Park is one of the few national parks to totally close[8] during the winter (generally, during the period of November 1 through April 15). The closure is due to the extreme winter weather conditions and difficulty of access from the mainland across a frozen Lake Superior, for the protection of wildlife, and for the safety and protection of potential visitors. Due to this total closure, there is very little nitrate haze impact in this park during the seasons of the year that it is open, and haze issues for Isle Royale National Park will not be further considered in this report.

The Seney Wilderness Area Visitor Center is open[9] only during the period of May 15th to mid-October. Various trails are generally only open during the same period. The tour loops are closed in the fall, winter, and spring to allow migrating and nesting birds a place to rest or nest undisturbed, and because of large amounts of snow. Although portions of the park are open in the winter, the visitation is greatly reduced due to no visitor center access, no trail or tour loop access, and the severe weather.

Effect of 2009 Recession on Haze in Affected PSD Class I Areas

The effect on haze of a significant (50%) emission reduction from the taconite plants that actually occurred in early 2009 and lasted throughout calendar year 2009 is discussed in this section. This emission reduction was not due to environmental regulations, but rather economic conditions, and affected all pollutants being emitted by the collective group of Minnesota taconite plants, as well as regional power production that is needed to operate the taconite plants.

The annual taconite production[10] from the Minnesota taconite plants in recent years is plotted in Figure 4, along with annual average nitrate concentrations at the nearest Class I area, Boundary Waters Canoe Area (BWCA). The figure shows that the nitrate measured in the park did not respond to the reduction in emissions from the taconite plants. Figures 5 and 6 show the time series[11] of nitrate and sulfate haze in

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[7] As documented at http://www.gorp.com/parks-guide/voyageurs-national-park-outdoor-pp2-guide-cid9423.html.

[8] As noted at http://www.nps.gov/isro/planyourvisit/hours.htm.

[9] As noted at http://www.fws.gov/midwest/seney/visitor_info.html.

[10] Production data is available from taxes levied on taconite production, and the data was supplied by BARR Engineering through a personal communication with Robert Paine of AECOM.

[11] Available from the VIEWS web site at http://views.cira.colostate.edu/web/.

the BWCA over the past several years. Figures for other affected Class I areas (Voyageurs, Seney, and Isle Royale) are shown in Appendix C.

Figure 4 Minnesota Taconite Production and BWCA Nitrate Concentrations

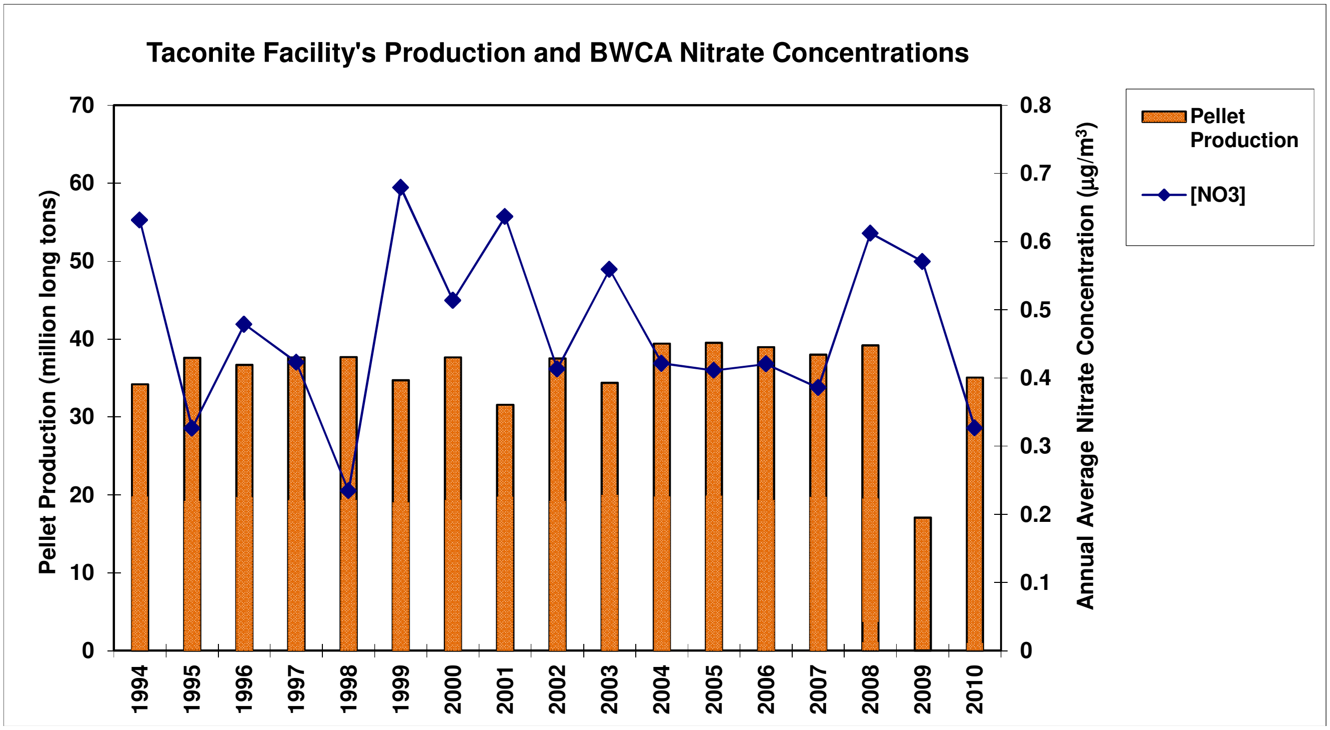


Figure 5 Time Series of Nitrate Haze at Boundary Waters Canoe Area (2002-2010)

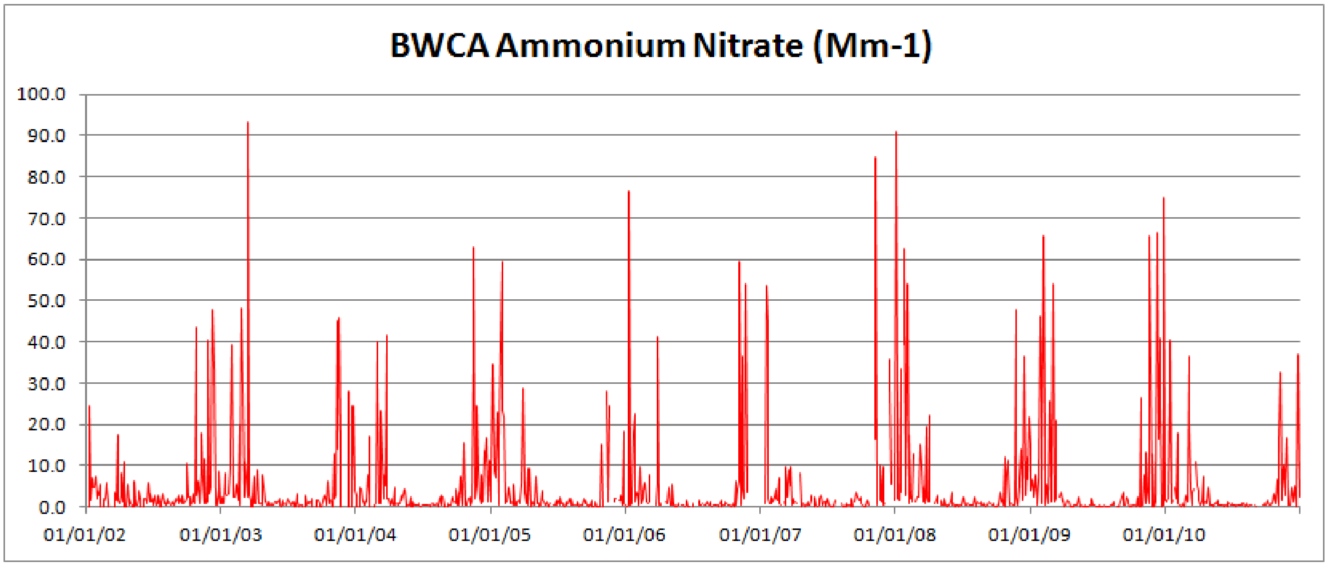
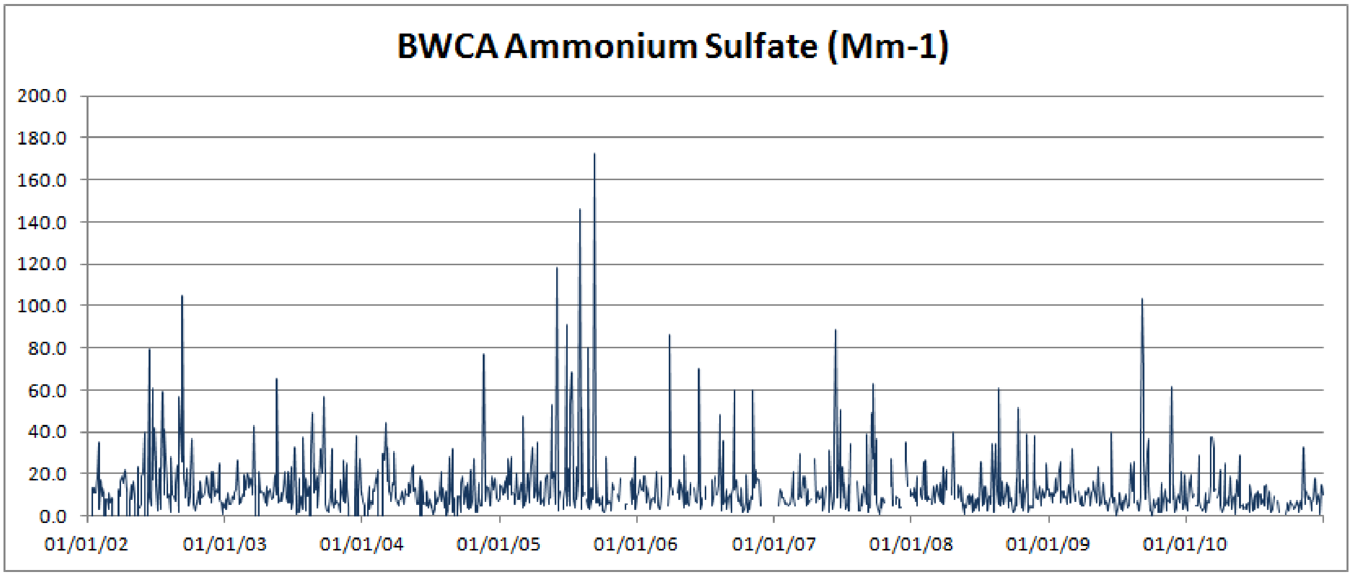


Figure 6 Time Series of Sulfate Haze at Boundary Waters Canoe Area (2002-2010)



It is evident from this information that the haze levels in BWCA did not, in general, decrease during 2009, and were therefore unaffected by emission reductions associated with the taconite production slowdown. It is noteworthy that peak events during mid-2009 in sulfate haze at BWCA when very little taconite production was occurring clearly indicate that minimal haze reduction would likely be associated with taconite plant emission reductions.

It is instructive to review the haze composition time series plots for BWCA for 2008, 2009, and 2010, as shown in Figures 7, 8, and 9.

Figure 7 Haze Composition Figure for Boundary Waters Canoe Area Wilderness, 2008

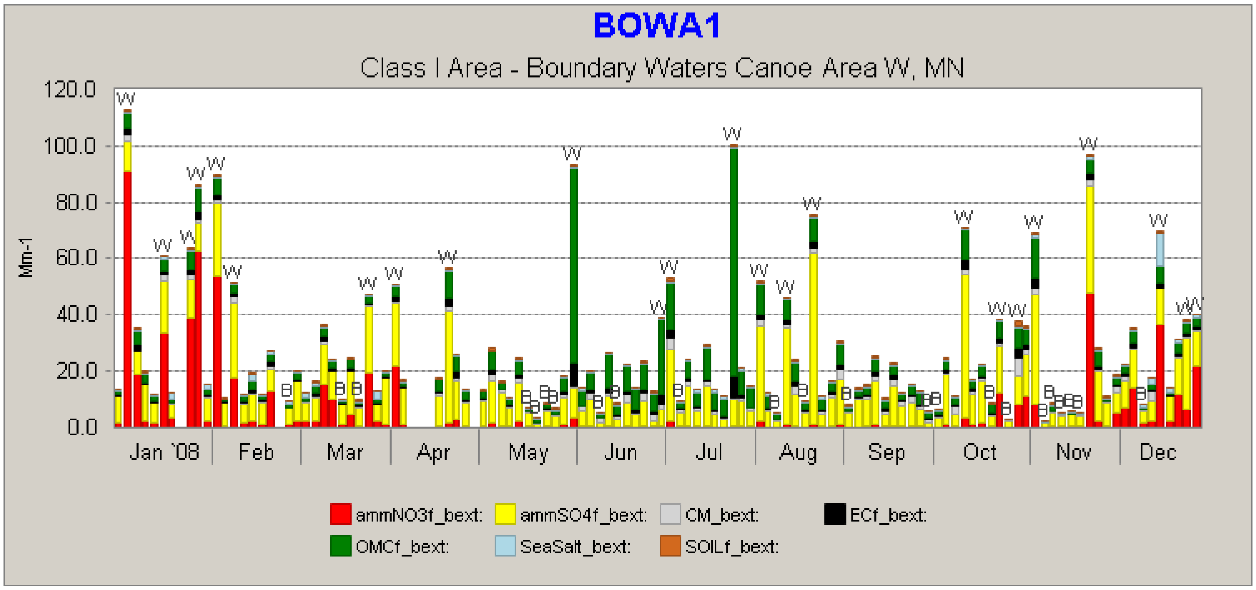


Figure 8 Haze Composition Figure for Boundary Waters Canoe Area Wilderness, 2009

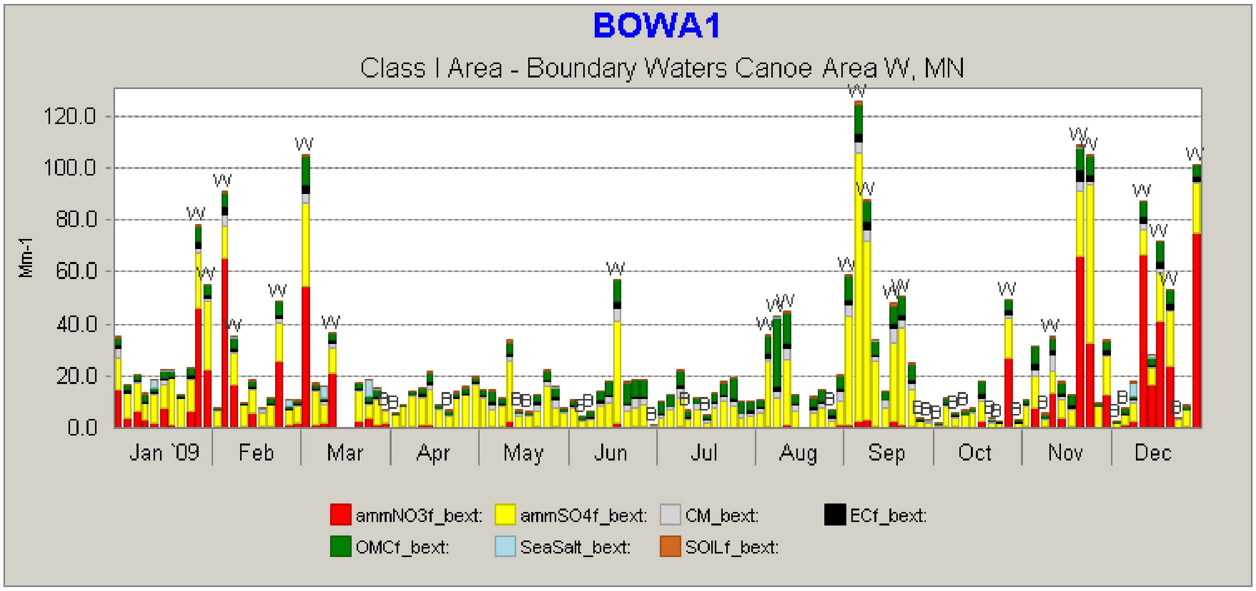
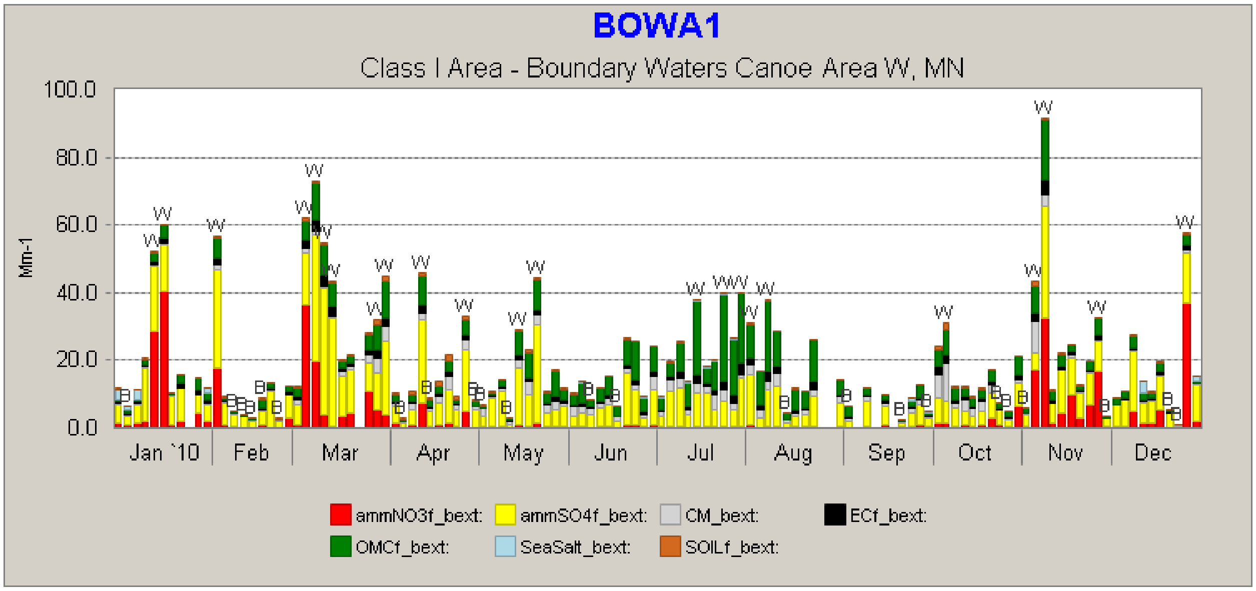


Figure 9 Haze Composition Figure for Boundary Waters Canoe Area Wilderness, 2010



As has been mentioned above, it is evident that the nitrate haze (red bars) is only important during the colder months (November through March). It is also evident that haze from forest fires (green bars) is predominant in the warm weather months, but varies from year to year according to the frequency of wildfires. For example, 2008 was a year of high occurrences of wildfires, while 2009 saw a low frequency, and 2010 was more normal.

The curtailment of taconite plant activity lasted from early 2009 through December 2009, peaking in the summer of 2009. Even so, we see the highest sulfate haze days (yellow bars) in September 2009 when taconite production was half of normal activity. Also, we note high nitrate haze days late in 2009 with the taconite plant curtailment that are comparable in magnitude to full taconite production periods in 2008. We also note that after the taconite plants went back to full production in 2010, the haze levels dropped, apparently due to emissions from other sources and/or states.

These findings suggest that reduction of emissions from the taconite plants will likely have minimal effects on haze in the nearby Class I areas. The fact that the various plants are distributed over a large area means that individual plumes are isolated and generally do not combine with others.

At least one other emission reduction opportunity to determine the effect on visibility improvement has occurred; this is related to the shutdown of the Mohave Generating Station in 2005, and its effect upon visibility in the Grand Canyon National Park. The discussion in Appendix D indicates that although CALPUFF modeling predicted substantial visibility benefits, very little change has occurred since 2005.

Other reasons that visibility assessment models such as CALPUFF could overpredict impacts are listed below.

1) The CALPUFF base case modeled scenario is always a worst-case emission rate which is assumed to occur every day. The actual emissions are often lower, and so the modeled improvement is an overestimate.

2) The way that the predicted concentrations are accounted for in the CALPOST output overstate the impact for even the case where the CALPUFF predictions are completely accurate. The way that CALPOST works is that the peak 24-hour prediction anywhere in a Class I area is the only information saved for each predicted day. The predicted impact for each day is effectively assumed to be a) always in the same place; and b) in all portions of the Class I area. Therefore, the 98th percentile day's prediction could be comprised of impacts in 8 different places that are all erroneously assumed to be co-located.

3) CALPUFF does not simulate dispersion and transport accurately over a full diurnal cycle, during which significant wind direction shear can occur (and is not properly accounted for by CALPUFF). This can result in plumes that are more cohesive than actually occur.

4) As discussed above, it is well established that nitrate predictions are often overstated by CALPUFF v. 5.8, especially in winter.

5) Natural conditions as input to CALPOST are not attainable, and their use will exaggerate the simulated visibility impacts of modeled emissions.

Interstate Non-Interference with Regional Haze Rule SIPs from Taconite Plant Emissions

An issue that is a recurring one for a number of state implementation plans (SIPs) is whether emissions from one state can interfere with haze reduction plans for downwind states. For Minnesota, it would be expected that emission reductions undertaken to reduce haze in Minnesota Class I areas (Voyageurs and Boundary Waters) would also act to reduce haze in other Class I areas. In the case of Minnesota's

taconite plant emissions, earlier discussions of the potentially affected Class I areas indicated that only the Class I areas in northern Michigan (Isle Royale National Park and Seney Wilderness Area) are close enough and in a general predominant wind direction to merit consideration. The closer of these two parks, Isle Royale, is closed to the public from November 1 through April 15, and haze effects there would not be affected by NO_X emissions because those effects are only important in the winter. Since Minnesota's Class I areas are located generally upwind of Michigan sources, the impact of Michigan sources on these Class I areas is expected to be small. This is confirmed in the Particulate Matter Source Apportionment Technology (PSAT) plots shown below.

Regional photochemical modeling studies[12] conducted by the CENRAP Regional Planning Organization, of which Minnesota is a part, shows contributions of various states as well as international contributions for haze impacts in the Michigan Class I areas. Relevant figures from the Iowa RHR SIP report for 2018 emission inventory haze impacts are reproduced below for Isle Royale National Park (Figure 10) and Seney Wilderness Area (Figure 11).

The modeling conducted for this analysis, using CAMx, shows that the relative contribution to haze for all Minnesota sources to sulfate haze in Isle Royale National Park is low, consisting of only 10% of the sulfate haze. The effect of 2018 emissions from Minnesota sources at the more distant Seney Wilderness Area is even lower, with the state's emissions ranking 9th among other jurisdictions analyzed for this Class I area. Therefore, it is apparent that Minnesota sources, and certainly the subset including taconite plants, would not be expected to interfere with other state's progress toward the 2018 milestone associated with the Regional Haze Rule.

Figures 12 and 13, reproduced from the Iowa RHR SIP report for Boundary Waters and Voyageurs, respectively, indicate that Michigan sources rank 11th and 12th, respectively, for haze impacts in these two areas for projected 2018 emissions. Therefore, as expected, Michigan sources are not expected to interfere with Minnesota's RHR SIP for progress in 2018.

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[12] See, for example, the Iowa State Implementation Plan for Regional Haze report at http://www.iowadnr.gov/portals/idnr/uploads/air/insidednr/rulesandplanning/rh_sip_final.pdf, Figures 11.3 and 11.4.

Figure 10 PSAT Results from CENRAP CAMx Modeling for Isle Royale National Park

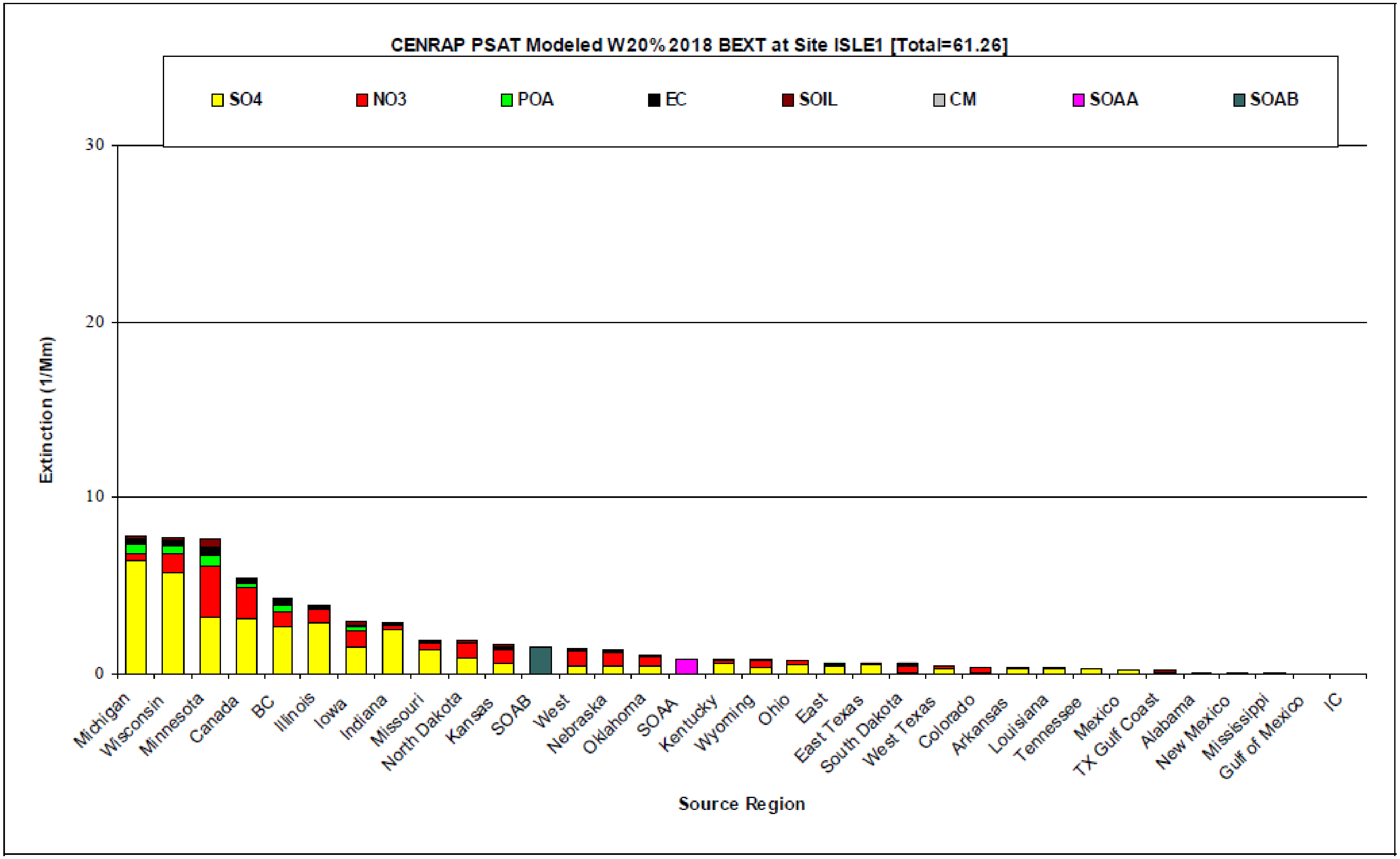


Figure 11.3. Source apportion contributions by region and pollutant to ISLE in 2018.

Figure 11 PSAT Results from CENRAP CAMx Modeling for Seney Wilderness Area

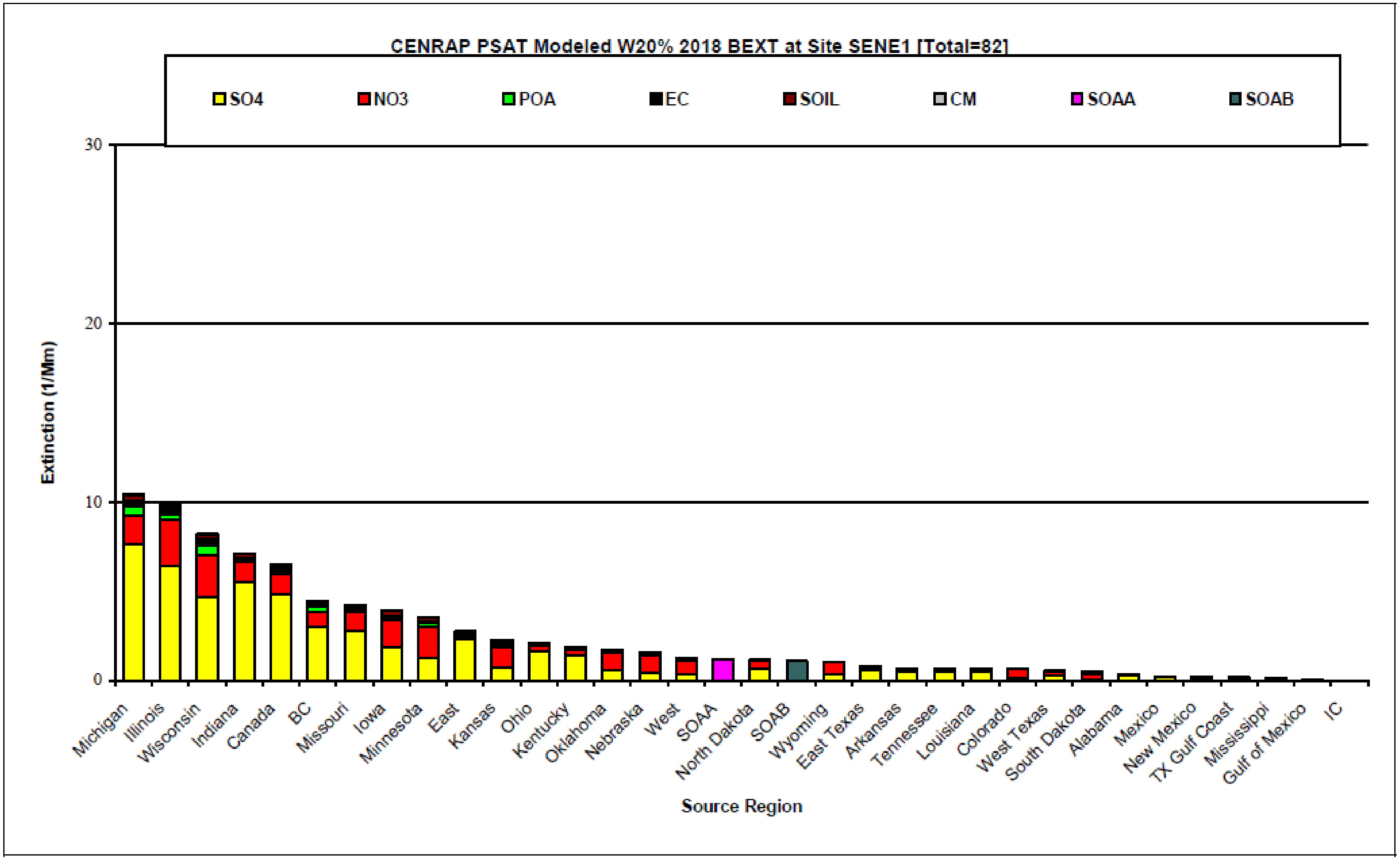


Figure 11.4. Source apportion contributions by region and pollutant to SENE in 2018.

Figure 12 PSAT Results from CENRAP CAMx Modeling for Boundary Waters Canoe Area Wilderness

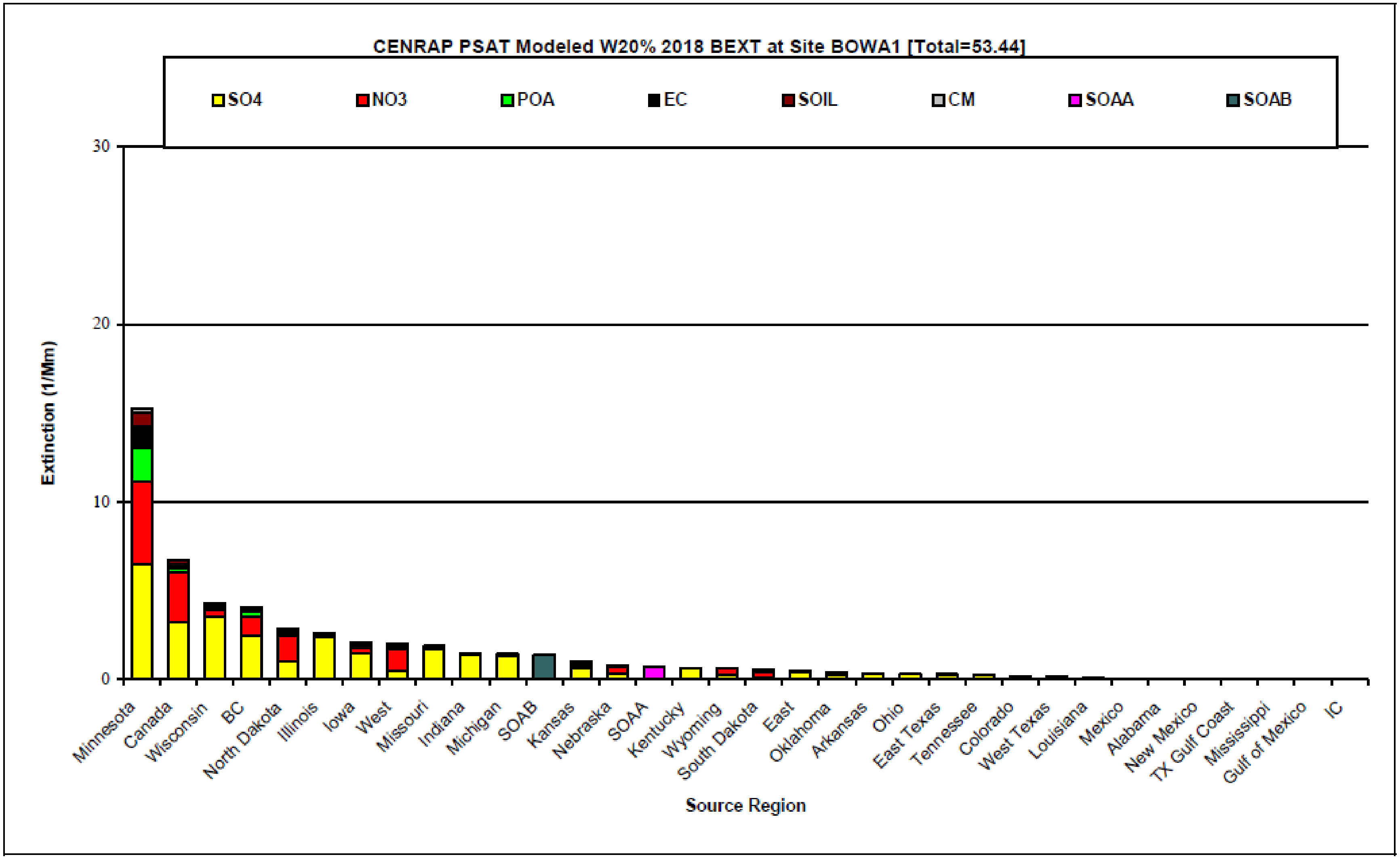


Figure 11.1. Source apportion contributions by region and pollutant to BOWA in 2018.

Figure 13 PSAT Results from CENRAP CAMx Modeling for Voyageurs National Park

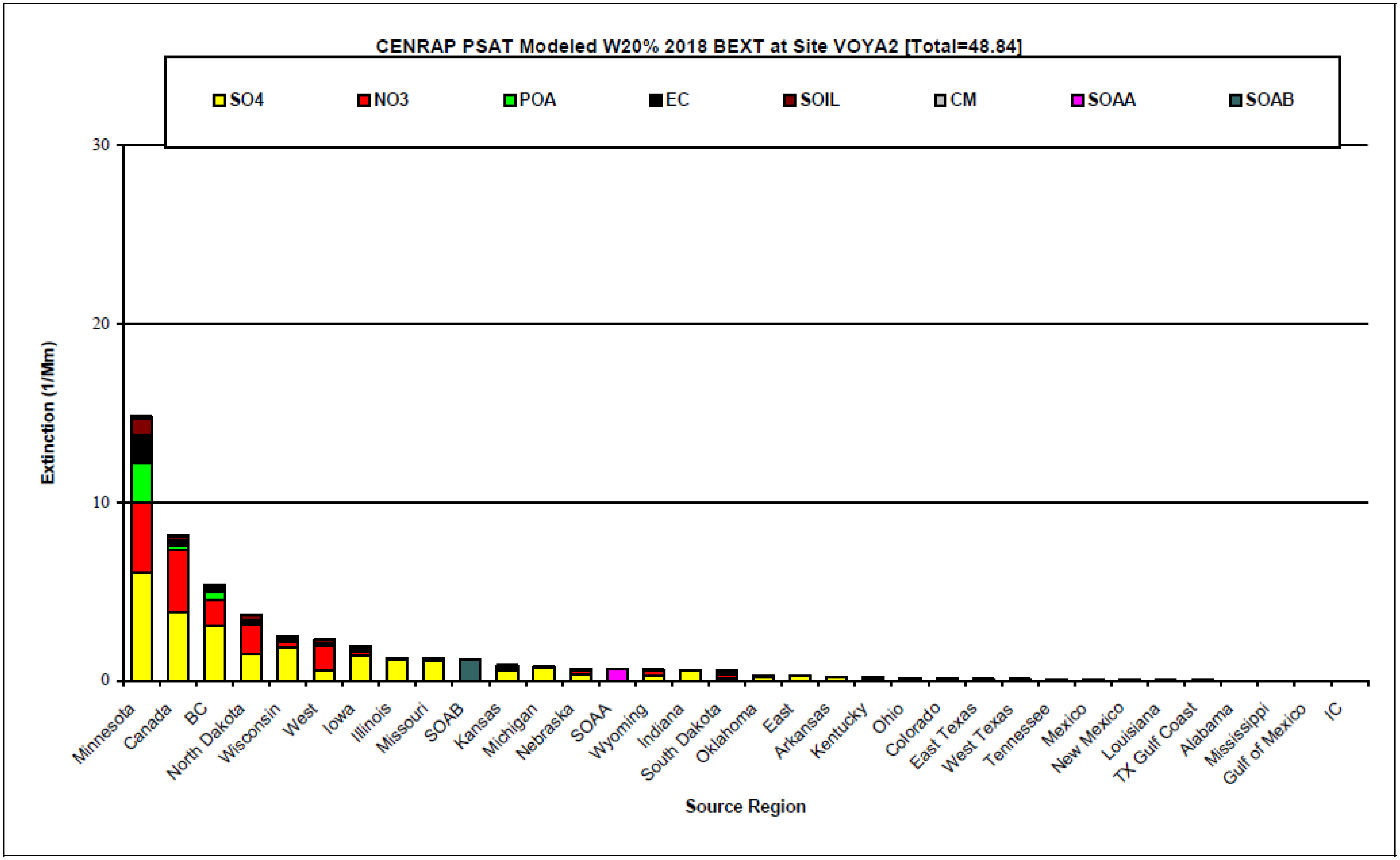


Figure 11.2. Source apportion contributions by region and pollutant to VOYA in 2018.

CONCLUSIONS

EPA's preferred modeling tools to assess the visibility improvement from BART controls will likely overestimate the predicted visibility improvement. While this is expected for all pollutants, it is especially true for NO_X emission controls. This occurs for several reasons:

- Natural background conditions, which are used in the calculation of haze impacts due to anthropogenic emissions, are mischaracterized as too clear, which exaggerates the impact of emission sources. Overly clean natural conditions can lead to the erroneous conclusion that some states are not adhering to the 2018 milestone because they need to achieve progress toward an impossible goal by the year 2064.
- The chemistry in the current EPA-approved version of CALPUFF as well as regional photochemical models overestimates winter nitrate haze, especially with the use of high ammonia background concentrations. There are other CALPUFF features that result in overpredictions of all pollutant concentrations. Therefore, BART emission reductions will be credited with visibility modeling for more visibility improvements than will really occur. We recommend that EPA adopt CALPUFF v. 6.42, which includes substantial improvements in the chemistry formulation. We also recommend the use of seasonally varying ammonia background concentrations, in line with observations and the current capabilities of CALPUFF.
- In addition to CALPUFF, the use of regional photochemical models results in significant nitrate haze overpredictions for Minnesota Class I area predictions.
- The modeled base case scenario is always a worst-case emission rate, assumed to occur every day. The actual emissions are often lower, and so the modeled improvement is an overestimate.

Impacts of the taconite plants' NO_X emissions are confined to winter months by the unique chemistry for nitrate particle formation. During these months, the attendance at the parks is greatly reduced by the closure of significant portions of the parks and the inability to conduct boating activities on frozen water bodies. In the case of Isle Royale National Park, there is total closure in the winter, lasting for 5 ½ months. The BART rule makes a provision for the consideration of such seasonal impacts. The imposition of NO_X controls year-round would not only have minimal benefits in the peak visitation season of summer, but also could lead to visibility disbenefits due to the increased power requirements (and associated emissions) needed for their operation, an effect that has not been considered in the visibility modeling.

Evidence of models' tendency for overprediction are provided in examples of actual significant emission reductions that have resulted in virtually no perceptive changes in haze, while visibility assessment modeling as conducted for BART would predict significant visibility improvements. These examples include the shutdown of the Mohave Generating Station (and minimal visibility effects at the Grand Canyon) as well as the economic slowdown that affected emissions from the taconite plants in 2009.

An analysis of the impact of the visibility impacts of Minnesota BART sources on Michigan's Class I areas, and vice versa indicates that the effects on the other state's Class I areas is minor. The taconite plant emissions are not expected to interfere with the ability of other states to achieve their required progress under the Regional Haze Rule.

APPENDIX A

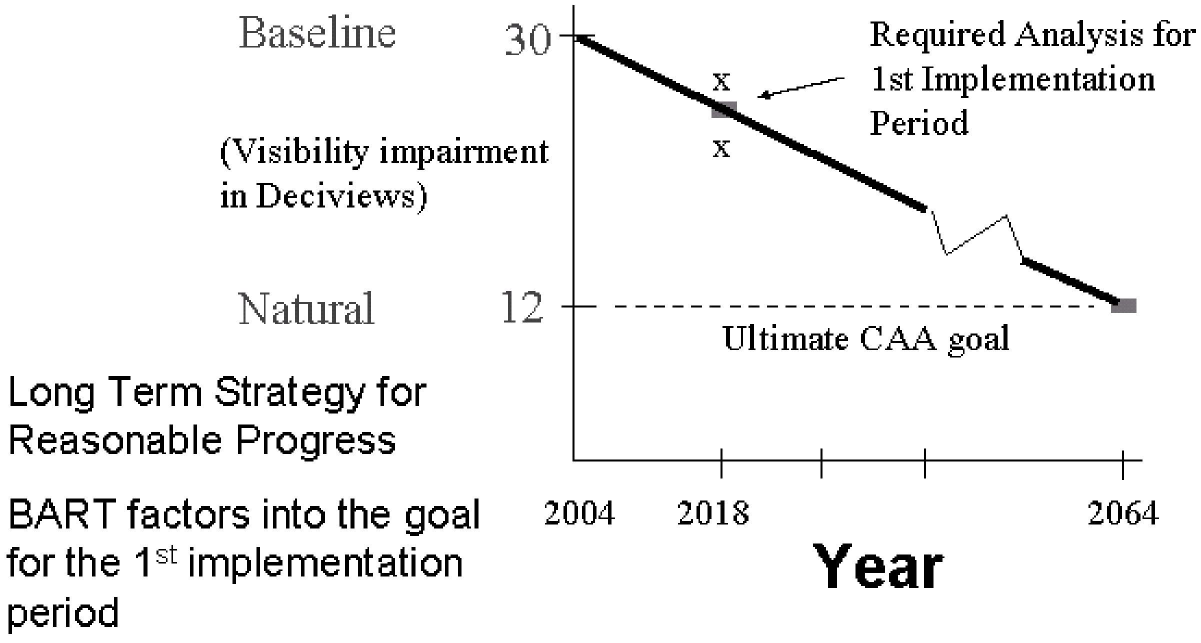
THE REGIONAL HAZE RULE GOAL OF NATURAL CONDITIONS

An important consideration in the ability for a state to meet the 2018 Uniform Rate of Progress (URP) goal is the definition of the end point goal of “natural conditions” for the worst 20% haze days; see Figure A-1, which illustrates this concept). Note that while achieving improved visibility for the worst 20% haze days, the RHR also stipulates that there should not be deterioration of visibility for the best 20%, or clearest, days. One way to define that goal would be the elimination of all man-made emissions. This raises some other questions, such as:

- To what categories of emissions does the RHR pertain?
- Does the current definition of natural conditions include non-anthropogenic or uncontrollable emissions?

The default natural background assumed by EPA in their 2003 guidance document[13] is not realistic. The discussion in this section explains why EPA’s default natural conditions significantly understate the true level of natural haze, including the fact that there are contributors of haze that are not controllable (and that are natural) that should be included in the definition of natural visibility conditions. In addition, one important aspect of the uncontrollable haze, wildfires, is further discussed regarding the biased quantification of its contribution to natural haze due to suppression of wildfires during the 20th century.

Figure A-1: Illustration of the Uniform Rate of Progress Goal



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[13] *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule*, (U.S. Environmental Protection Agency, September 2003). http://www.epa.gov/ttncaaa1/t1/memoranda/rh_envcurhr_gd.pdf.

In its RHR SIP, North Dakota[14] noted in Section 9.7 that,

"Achieving natural conditions will require the elimination of all anthropogenic sources of emissions. Given current technology, achieving natural conditions is an impossibility. Any estimate of the number of years necessary to achieve natural visibility conditions would require assumptions about future energy sources, technology improvements for sources of emissions, and every facet of human behavior that causes visibility impairing emissions. The elimination of all SO_2 and NO_x emissions in North Dakota will not achieve the uniform rate of progress for this [2018], or any future planning period. Any estimate of the number of years to achieve natural conditions is questionable because of the influence of out-of-state sources."

It will be extremely difficult, if not impossible, to eliminate all anthropogenic emissions, even if natural conditions are accurately defined. It will be even more daunting to try to reach the goal if natural conditions are significantly understated, and as a result, states are asked to control sources that are simply not controllable. It is clear that the use of EPA default natural conditions leads to unworkable and absurd results for one state's (North Dakota's) ability to determine the rate of progress toward an unattainable goal. The definition of natural conditions that can be reasonably attained for a reasonable application of USEPA's Regional Haze Rule should be revised for all states.

The objective of the following discussion is to summarize recent modeling studies of natural visibility conditions and to suggest how such studies can be used in evaluating the uniform rate of progress in reducing haze to attain natural visibility levels. In addition, the distinction between natural visibility and policy relevant background visibility is discussed. Treatment of this issue by other states, such as Texas, is also discussed.

Regional Haze Issues for Border States

There are similarities between the Regional Haze Rule (RHR) challenges for border states such as North Dakota and Texas in that both states have significant international and natural contributions to regional haze in Class I areas in their states. The Texas Commission on Environmental Quality (TCEQ) has introduced alternative RHR glide paths to illustrate the State's rate of progress toward the RHR goals. Since TCEQ has gone through the process of a RHR State Implementation Plan (SIP) development and comment period, it is instructive to look at the TCEQ approach, the comments provided by the Federal Land Managers to TCEQ, and TCEQ's reaction to the comments.

Similarities to be considered for the RHR SIP development in border states, such as North Dakota and Texas, include the items listed below.

- These states have Class I areas for which a considerable fraction of the regional haze is due to international transport or transport from other regions of the United States.

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[14] North Dakota Dep. of Health, 2010. North Dakota State Implementation Plan for Regional Haze. http://www.ndhealth.gov/AQ/RegionalHaze/Regional%20Haze%20Link%20Documents/Main%20SIP%20Sections%201-12.pdf.
.

- As a result, there is a substantial reduction in SO_2 and NO_x emissions from the BART-eligible sources in each state, but this reduction results in a relatively small impact on regional haze mitigation. Additional emission reductions would, therefore, have a minimal benefit on visibility improvement at substantial cost.
- In the Regional Haze SIP development, these states have attempted to account for the effects of anthropogenic emissions that they can control in alternative analyses. These analysis result in a finding that the in-state emission reductions come closer to meeting the Uniform Rate of Progress glide path goals for 2018. However, due to the low probability of impact of these sources on the worst 20% days, the effectiveness of in-state emission controls on anthropogenic sources subject to controls is inherently limited.

TCEQ decided that coarse and fine PM measured at the Class I areas were due to natural causes (especially on the worst 20% days), and adjusted the natural conditions endpoint accordingly. The Federal Land Managers (FLMs) agreed with this approach for the most part[15], but suggested that 80% of these concentrations would be due to natural causes, and 20% would be due to anthropogenic causes. TCEQ determined from a sensitivity analysis that the difference in these two approaches was too small to warrant a re-run of their analysis, but it is important that the FLMs agreed to a state-specific modification of the natural conditions endpoint, and this substantially changed the perceived rate of progress of the SIP plan toward the altered natural conditions endpoint.

Although the TCEQ did not address other particulate matter components in this same way, a review of air parcel back trajectories previously available from the IMPROVE web site (http://views.cira.colostate.edu/web/) suggests that other components, such as organic matter due to wildfires, could be substantially due to natural causes, so that this component should also be considered as at least partially natural.

The TCEQ discussed the issue of how emissions from Mexico could interfere with progress on the RHR, but they did not appear to adjust the glide path based upon Mexican emissions. On the other hand, in its weight of evidence analysis, North Dakota did evaluate adjustments based upon anthropogenic emissions that could not be controlled from Canadian sources, but did not take into account any specific particulate species that are generally not emitted by major anthropogenic sources of SO_2 and NO_X.

Natural Haze Levels

The Regional Haze Rule establishes the goal that natural visibility conditions should be attained in Federal Class I areas by the year 2064. Additionally, the states are required to determine the uniform rate of progress (URP) of visibility improvement necessary to attain the natural visibility goal by 2064. Finally, each state must develop a SIP identifying reasonable control measures that will be adopted well before 2018 to reduce source emissions of visibility-impairing particulate matter (PM) and its precursors (SO_2 and NO_x).

Estimates of natural haze levels have been developed by the EPA for visibility planning purposes and are described in the above-referenced EPA 2003 document. The natural haze estimates were based on ambient data analysis of selected PM species for days with good visibility and are shown in Table A-1.

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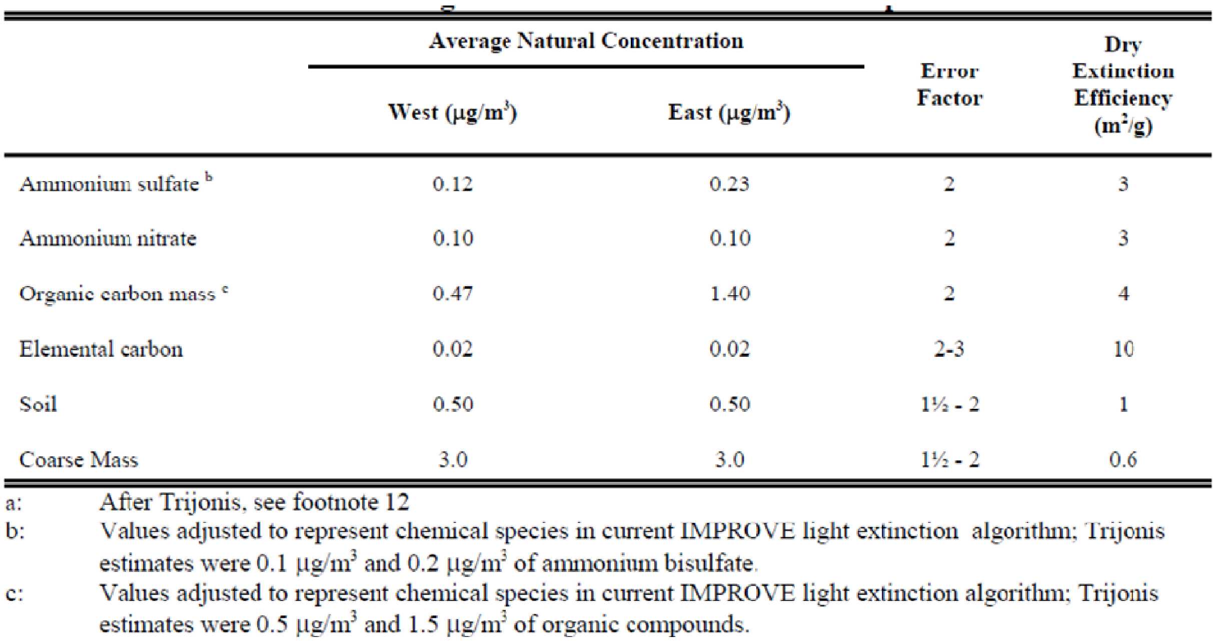
[15] See Appendix 2-2 at http://www.tceq.state.tx.us/implementation/air/sip/bart/haze_appendices.html.

These estimates were derived from Trijonis[16] and use two different sets of natural concentrations for the eastern and western U.S. Tombach[17] provides a detailed review and discussion of uncertainty in the USEPA natural PM estimates. Natural visibility can be calculated using the IMPROVE equation which calculates the light scattering caused by each component of PM. After much study, changes in the IMPROVE equation and in the method for calculating natural visibility were developed in 2005 and are described by Pitchford et al.[18]

Table A-1: Average Natural Levels of Aerosol Components from Table 2-1 of *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule* (EPA, 2003)



	Average Natural Concentration		Error Factor	Dry Extinction Efficiency (m^2/g)
	West ($\mu g/m^3$)	East ($\mu g/m^3$)		
Ammonium sulfate [b]	0.12	0.23	2	3
Ammonium nitrate	0.10	0.10	2	3
Organic carbon mass [c]	0.47	1.40	2	4
Elemental carbon	0.02	0.02	2-3	10
Soil	0.50	0.50	1½ - 2	1
Coarse Mass	3.0	3.0	1½ - 2	0.6

a: After Trijonis, see footnote 12

b: Values adjusted to represent chemical species in current IMPROVE light extinction algorithm; Trijonis estimates were 0.1 $\mu g/m^3$ and 0.2 $\mu g/m^3$ of ammonium bisulfate.

c: Values adjusted to represent chemical species in current IMPROVE light extinction algorithm; Trijonis estimates were 0.5 $\mu g/m^3$ and 1.5 $\mu g/m^3$ of organic compounds.

The EPA guidance also makes provision for refined estimates of site-specific natural haze that differ from the default values using either data analysis or model simulations. However, most states have continued to use the default natural haze levels for calculating the progress toward natural visibility conditions.

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[16] Trijonis, J. C. Characterization of Natural Background Aerosol Concentrations. Appendix A in Acidic Deposition: State of Science and Technology. Report 24. Visibility: Existing and Historical Conditions -- Causes and Effects. J. C. Trijonis, lead author. National Acid Precipitation Assessment Program: Washington, DC, 1990.

[17] Tombach, I., (2008) *Natural Haze Levels Sensitivity -- Assessment of Refinements to Estimates of Natural Conditions,* Report to the Western Governors Association, January 2008, available at http://www.wrapair.org/forums/aamrf/projects/NCB/index.html.

[18] Pitchford, M., Malm, W., Schichtel, B., Kumar, N., Lowenthal, D., Hand, J., Revised Algorithm for Estimating Light Extinction from IMPROVE Particle Speciation Data, J. Air & Waste Manage, Assoc. 57: 1326 – 1336, 2007.

Tombach and Brewer[19] reviewed natural sources of PM and identified several Class I areas for which evidence supports adjustments to the natural levels. Tombach[8] also reviewed estimates of natural haze levels and proposed that, instead of using two sets of default natural PM concentrations for the eastern and western US, a large number of sensitivity zones should be developed that reflect regional variability in natural PM sources. Tombach[8] also suggested that modeling studies are a possible approach to further revise estimates of natural PM concentrations.

Previous modeling studies have shown that the estimates of natural visibility described above for "clean" days will differ from the results of model simulations when United States anthropogenic emissions are totally eliminated (Tonnesen et al., 2006[20]; Koo et al., 2010[21]), especially when natural wild fire emissions are included in the model simulation. Because the URP is calculated using model simulations of PM on the 20% of days with the worst visibility, wild fires and other extreme events can result in estimated levels of natural haze (even without any contribution of US anthropogenic sources) that can be significantly greater than the natural levels used in the EPA guidance for URP calculation. This could make it difficult or impossible for states to identify emissions control measures sufficient to demonstrate the URP toward attaining visibility goals because the endpoint is unachievable even if all US anthropogenic emissions are eliminated, as North Dakota has already determined even for the interim goal in 2018.

Previous Suppression of Wildfire Activity and its Effect upon the EPA Default Natural Conditions

Throughout history, except for the past few decades, fires have been used to clear land, change plant and tree species, sterilize land, maintain certain types of habitat, among other purposes. Native Americans used fires as a technique to maintain certain pieces of land or to improve habitats. Although early settlers often used fires in the same way as the Native Americans, major wildfires on public domain land were largely ignored and were often viewed as an opportunity to open forestland for grazing.

Especially large fires raged in North America during the 1800s and early 1900s. The public was becoming slowly aware of fire's potential for life-threatening danger. Federal involvement in trying to control forest fires began in the late 1890s with the hiring of General Land Office rangers during the fire season. When the management of the forest reserves (now called national forests) was transferred to the newly formed Forest Service in 1905, the agency took on the responsibility of creating professional standards for firefighting, including having more rangers and hiring local people to help put out fires.

Since the beginning of the 20th century, fire suppression has resulted in a buildup of vegetative "fuels" and catastrophic wildfires. Recent estimates of background visual range, such as Trijonis[16], have underestimated the role of managed fire on regional haze. Since about 1990, various government agencies have increased prescribed burning to reduce the threat of dangerous wildfires, and the

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[19] Tombach, I., and Brewer, P. (2005). Natural Background Visibility and Regional Haze Goals in the Southeastern United States. *J. Air & Waste Manage. Assoc. 55*, 1600-1620.

[20] Tonnesen, G., Omary, M., Wang, Z., Jung, C.J., Morris, R., Mansell, G., Jia, Y., Wang, B., and Z. Adelman (2006) Report for the Western Regional Air Partnership Regional Modeling Center, University of California Riverside, Riverside, California, November. (http://pah.cert.ucr.edu/aqm/308/reports/final/2006/WRAP-RMC_2006_report_FINAL.pdf).

[21] Koo B., C.J. Chien, G. Tonnesen, R. Morris , J. Johnson, T. Sakulyanontvittaya, P. Piyachaturawat, and G.Yarwood, 2010. Natural emissions for regional modeling of background ozone and particulate matter and impacts on emissions control strategies. Atm. Env., 44, 2372-2382.

increased haze due to these fires is often more of an impairment to visibility than industrial sources, especially for NO_X reductions that are only effective in winter, the time of the lowest tourist visitation in most cases.

The National Park Service indicates at http://www.nps.gov/thro/parkmgmt/firemanagement.htm for the Theodore Roosevelt National Park that:

"For most of the 20th Century, wildfires were extinguished immediately with the assumption that doing so would protect lives, property, and natural areas. However, following the unusually intense fire season of 1988, agencies including the National Park Service began to rethink their policies." Even this policy is not always successful, as experienced by the USDA Forest Service[22] in their management of wildfires near the Boundary Waters Canoe Area that can contribute significantly to visibility degradation during the peak tourist season. In this case, even small fires, if left unchecked, have been known to evolve into uncontrollable fires and then require substantial resources to extinguish.

EPA's 2003 "Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program" acknowledges that wildfires are a contributor to natural visibility conditions, but the data used in estimates of natural conditions were taken during a period of artificial fire suppression so that the true impact of natural wildfires is understated. The report notes that "data should be available for EPA and States to develop improved estimates of the contribution of fire emissions to natural visibility conditions in mandatory Federal Class I areas over time." As noted by several studies noted above, the impact due to natural fire levels is underestimated in the EPA natural visibility background estimates. The consequences of the artificially low estimates of natural visibility conditions include the distortion of Reasonable Progress analyses and also to BART modeling results that overestimate the visibility improvement achievable from NO_X emission reductions due to the use of inaccurate natural visibility conditions.

Recommendations for an Improved Estimate of Visibility Natural Conditions

A reasonable approach would be to combine the effects of the uncontrollable particulate matter components and the emissions from international sources to determine a new glide path endpoint that is achievable by controlling (only) U.S. anthropogenic emissions. To compute this new endpoint, regional photochemical modeling using CMAQ or CAMx could be conducted for the base case (already done) and then for a future endpoint case that has no U.S. anthropogenic emissions, but with natural particulate matter emissions (e.g., dust, fires, organic matter) as well as fine particulate, SO_2 and NO_x emissions associated with all non-U.S. sources set to the current baseline levels. The simulation should include an higher level of wildfire activity than in the recent past to reflect a truer level of fire activity before manmade suppression in the 20th century. Then, states could use a relative reduction factor (RRF) approach to determine the ratio of the haze impacts between the base case and the reasonable future case, and then apply the RRF values to the baseline haze to obtain a much more reasonable "natural conditions" haze endpoint. The more accurate natural background would also result in a reduction in the degree to which CALPUFF modeling overstates visibility improvement from emission reductions.

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[22] See explanation at http://www.msnbc.msn.com/id/48569985/ns/us_news-environment/t/forest-service-gets-more-aggressive-small-fires/.

APPENDIX B

MODEL OVERPREDICTION ISSUES FOR WINTERTIME NITRATE HAZE

This appendix includes a discussion of CALPUFF predictions for nitrate haze, followed by more general issues with CALPUFF predictions.

CALPUFF Predictions of Nitrate Haze

Secondary pollutants such as nitrates and sulfates contribute to light extinction in Class I areas. The CALPUFF model was approved by EPA for use in BART determinations to evaluate the effect of these pollutants on visibility in Class I areas. CALPUFF version 5.8 (the current guideline version) uses the EPA-approved MESOPUFF II chemical reaction mechanism to convert SO_2 and NO_X emissions to secondary sulfate and nitrate. This section describes how secondary pollutants, specifically nitrate, are formed and the factors affecting their formation, especially as formulated in CALPUFF.

In the CALPUFF model, the oxidation of NO_X to nitric acid (HNO_3) depends on the NO_X concentration, ambient ozone concentration, and atmospheric stability. Some of the nitric acid is then combined with available ammonia in the atmosphere to form ammonium nitrate aerosol in an equilibrium state that is a function of temperature, relative humidity, and ambient ammonia concentration. In CALPUFF, total nitrate ($TNO_3 = HNO_3 + NO_3$) is partitioned into gaseous HNO_3 and NO_3 particles according to the equilibrium relationship between the two species. This equilibrium is a function of ambient temperature and relative humidity. Moreover, the formation of nitrate particles *strongly* depends on availability of NH_3 to form ammonium nitrate, as shown in Figure 6[23]. The figure on the left shows that with 1 ppb of available ammonia and fixed temperature and humidity (for example, 275 K and 80% humidity), only 50% of the total nitrate is in the form of particulate matter. When the available ammonia is increased to 2 ppb, as shown in the figure on the right, as much as 80% of the total nitrate is in the particulate form. Figure B-1 also shows that colder temperatures and higher relative humidity favor particulate nitrate formation. A summary of the conditions affecting nitrate formation are listed below:

- Colder temperature and higher relative humidity create more favorable conditions to form nitrate particulate matter in the form of ammonium nitrate;
- Warmer temperatures and lower relative humidity create less favorable conditions for nitrate particulate matter resulting in a small fraction of total nitrate in the form of ammonium nitrate;
- Ammonium sulfate formation preferentially scavenges available atmospheric ammonia over ammonium nitrate formation. In air parcels where sulfate concentrations are high and ambient ammonia concentrations are low, there is less ammonia available to react with nitrate, and less ammonium nitrate is formed.

The effects of temperature and background ammonia concentrations on the nitrate formation are the key to understanding the effects of various NO_X control options. For the reasons discussed above, the seasons with lower temperatures are the most likely to be most important for ammonium nitrate formation when regional haze is more effectively reduced by controlling NO_X.

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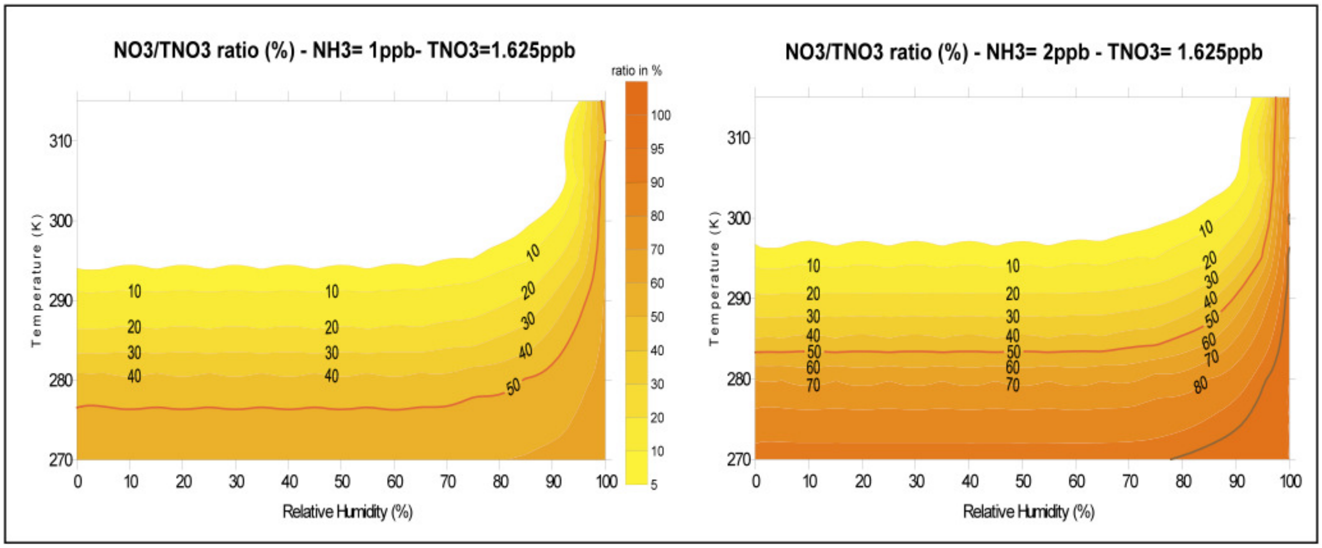
[23] Scire, Joseph. CALPUFF MODELING SYSTEM. CALPUFF course presented at Chulalongkorn University, Bangkok, Thailand. May 16-20, 2005; slide 40 available at http://aqnis.pcd.go.th/tapce/plan/4CALPUFF%20slides.pdf, accessed March 2011.

Figure B-1: NO_3/HNO_3 Equilibrium Dependency on Temperature and Humidity



Sensitivity of CALPUFF Haze Calculations to Background Ammonia Concentration

In an independent analysis, the Colorado Department of Public Health and Environment (CDPHE) performed a sensitivity modeling analysis to explore the effect of the specified ammonia concentration applied in CALPUFF on the predicted visibility impacts for a source with high NO_X emissions relative to SO_2 emissions[24]. The results of the sensitivity modeling are shown in Figure B-2. It is noteworthy that the largest sensitivity occurs for specified ammonia input between 1 and 0.1 ppb. In that factor-of-ten range, the difference in the peak visibility impact predicted by CALPUFF is slightly more than a factor of three. This sensitivity analysis shows that the specification of background ammonia is very important in terms of the magnitude of visibility impacts predicted by CALPUFF. The fact that regional, diurnal and seasonal variations of ambient ammonia concentrations are not well-characterized and mechanisms not well-understood effectively limits the effectiveness of CALPUFF in modeling regional haze, especially in terms of the contribution of ammonium nitrate.

It is also noteworthy that CALPUFF version 5.8's demonstrated over-predictions of wintertime nitrate can be mitigated to some extent by using lower winter ammonia background values, although there is not extensive measurement data to determine the ambient ammonia concentrations. This outcome showing the superiority of the monthly-varying background ammonia concentrations was found by Salt River

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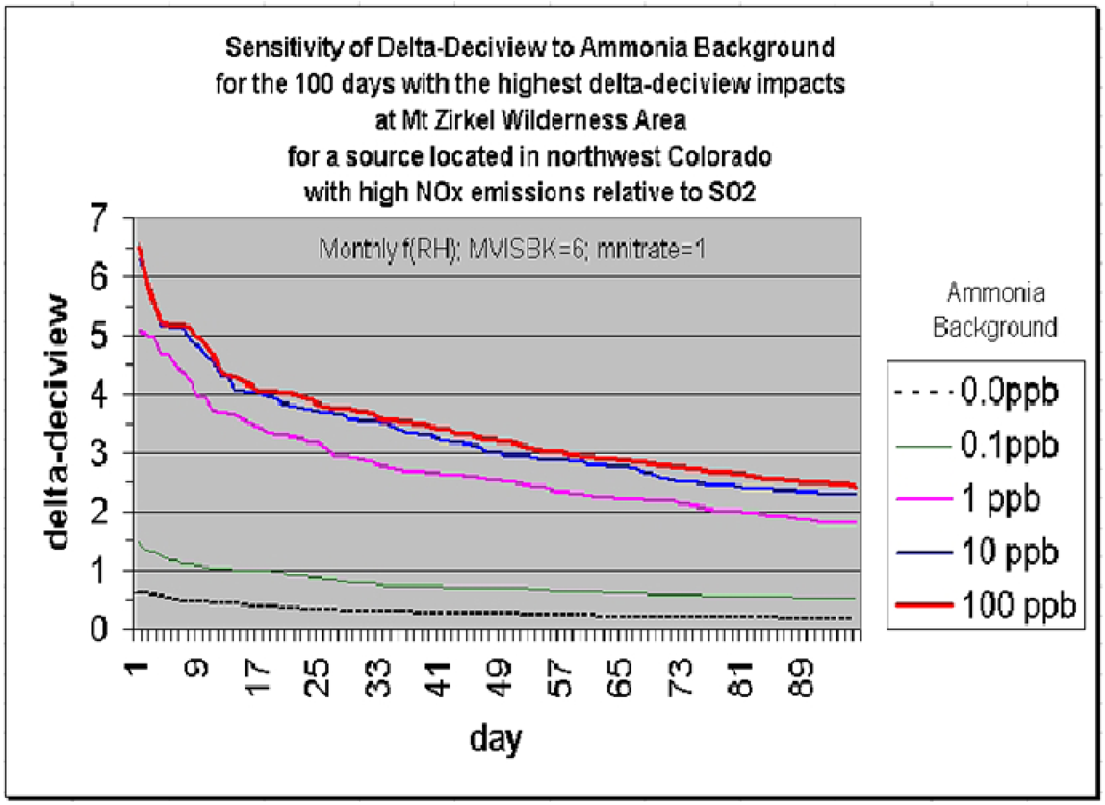
[24] Supplemental BART Analysis: CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis (DRAFT), revised June 25, 2010, available at http://www.colorado.gov/airquality/documents/Draft-ColoradoSupplementalBARTAnalysisCALPUFFProtocol-25June2010.pdf. (2010)

Project in case studies of the Navajo Generating Station impacts on Grand Canyon monitors, as presented[25] to EPA in 2010.

It is important to note that 14 years ago in 1998, when the IWAQM Phase 2 guidance[26] was issued, CALPUFF did not even have the capability of accommodating monthly ammonia background concentrations; only a single value was allowed. Since then, CALPUFF has evolved to be able to receive as input monthly varying ammonia concentrations. EPA's guidance on the recommended input values that are constant all year has not kept pace with the CALPUFF's capability. The weight of evidence clearly indicates that the use of monthly varying ammonia concentrations with lower wintertime values will result in more accurate predictions.

Figure B-2: CDPHE Plot of Sensitivity of Visibility Impacts Modeled by CALPUFF for Different Ammonia Backgrounds.



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[25] Salt River Project, 2010. Measurements of Ambient Background Ammonia on the Colorado Plateau and Visibility Modeling Implications. Salt River Project, P.O. Box 52025 PAB352, Phoenix, Arizona 85072.

[26] IWAQM Phase 2 Summary Report and Recommendations (EPA-454/R-98-019), EPA OAQPS, December 1998). http://www.epa.gov/scram001/7thconf/calpuff/phase2.pdf.

Independent Studies of the Effect of Model Chemistry on Nitrate Predictions

The Regional Haze BART Rule acknowledged that CALPUFF tends to overestimate the amount of nitrate that is produced. In particular, the overestimate of ammonium nitrate concentrations on visibility at Class I areas is the greatest in the winter, when temperatures (and visitation) are lowest, the nitrate concentrations are the greatest, and the sulfate concentrations tend to be the least due to reduced oxidation rates of SO_2 to sulfate.

On page 39121, the BART rule[27] stated that: "…the simplified chemistry in the [CALPUFF] model tends to magnify the actual visibility effects of that source."

On page 39123, the BART rule stated that: "We understand the concerns of commenters that the chemistry modules of the CALPUFF model are less advanced than some of the more recent atmospheric chemistry simulations. In its next review of the Guideline on Air Quality Models, EPA will evaluate these and other newer approaches[28]."

EPA did not conduct such an evaluation, but the discussion below reports on the efforts of other investigators.

A review of independent evaluations of the CALPUFF model is reported here, with a focus on identifying studies that address the nitrate chemistry used in the model. Morris et al.[29] reported that the CALPUFF MESOPUFF II transformation rates were developed using temperatures of 86, 68 and 50°F. Therefore, the 50°F minimum temperature used in development of the model could result in overestimating sulfate and nitrate formation in colder conditions. These investigators found that CALPUFF tended to overpredict nitrate concentrations during winter by a factor of about three.

A recent independent study of the CALPUFF performance by Karamchandani et al (referred to here as the KCBB study) is highly relevant to this issue[30]. The KCBB study presented several improvements to the Regional Impacts on Visibility and Acid Deposition (RIVAD) chemistry option in CALPUFF, an alternative treatment that was more amenable to an upgrade than the MESOPUFF II chemistry option. Among other items, the improvements included the replacement of the original CALPUFF secondary particulate matter (PM) modules by newer algorithms that are used in current state-of-the-art regional air quality models such as CMAQ, CMAQ-MADRID, CAMx and REMSAD, and in advanced puff models

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[27] July 6, 2005 Federal Register publication of the Regional Haze BART rule.

[28] The next (9th) EPA modeling conference was held in 2008, during which the concepts underlying the chemistry upgrades in CALPUFF 6.42 were presented. However, EPA failed to conduct the promised evaluation in its review of techniques at that conference held 4 years ago. As a result of the 10th EPA modeling conference held in March 2012, EPA appears to be continuing to rely upon CALPUFF version 5.8, which it admitted in the July 6, 2005 BART rule has serious shortcomings.

[29] Morris, R., Steven Lau and Bonyoung Koo. Evaluation of the CALPUFF Chemistry Algorithms. Presented at A&WMA 98th Annual Conference and Exhibition, June 21-25, 2005 Minneapolis, Minnesota. (2005)

[30] Karamchandani, P., S. Chen, R. Bronson, and D. Blewitt. Development of an Improved Chemistry Version of CALPUFF and Evaluation Using the 1995 SWWYTAF Data Base. Presented at the Air & Waste Management Association Specialty Conference on Guideline on Air Quality Models: Next Generation of Models, October 28-30, 2009, Raleigh, NC. (2009)

such as SCICHEM. In addition, the improvements included the incorporation of an aqueous-phase chemistry module based on the treatment in CMAQ. Excerpts from the study papers describing each of the improvements made to CALPUFF in the KCBB study are repeated below.

Gas-Phase Chemistry Improvements

The KCBB study applied a correction to CALPUFF in that the upgraded model was modified to keep track of the puff ozone concentrations between time steps. The authors also updated the oxidation rates of SO_2 and nitrogen dioxide (NO_2) by the hydroxide ion (OH^-) to the rates employed in contemporary photochemical and regional PM models.

Treatment of Inorganic Particulate Matter

The KCBB study scientists noted that the EPA-approved version of CALPUFF currently uses a simple approach to simulate the partitioning of nitrate and sulfate between the gas and particulate phases. In this approach, sulfate is appropriately assumed to be entirely present in the particulate phase, while nitrate is assumed to be formed by the reaction between nitric acid and ammonia.

The KCBB study implemented an additional treatment for inorganic gas-particle equilibrium, based upon an advanced aerosol thermodynamic model referred to as the ISORROPIA model[31]. This model is currently used in several state-of-the-art regional air quality models. With this new module, the improved CALPUFF model developed in the KCBB study includes a treatment of inorganic PM formation that is consistent with the state of the science in air quality modeling, and is critical for the prediction of regional haze due to secondary nitrate formation from NO_X emissions.

Treatment of Organic Particulate Matter

The KCBB study added a treatment for secondary organic aerosols (SOA) that is coupled with the corrected RIVAD scheme described above. The treatment is based on the Model of Aerosol Dynamics, Reaction, Ionization and Dissolution (MADRID)[32,33], which treats SOA formation from both anthropogenic and biogenic volatile organic compound emissions.

Aqueous-Phase Chemistry

The current aqueous-phase formation of sulfate in both CALPUFF's RIVAD and MESOPUFF II schemes is currently approximated with a simplistic treatment that uses an arbitrary pseudo-first order rate in the presence of clouds (0.2% per hour), which is added to the gas-phase rate. There is no explicit treatment

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[31] Nenes A., Pilinis C., and Pandis S.N. Continued Development and Testing of a New Thermodynamic Aerosol Module for Urban and Regional Air Quality Models, *Atmos. Env.* **1998**, 33, 1553-1560.

[32] Zhang, Y., B. Pun, K. Vijayaraghavan, S.-Y. Wu, C. Seigneur, S. Pandis, M. Jacobson, A. Nenes and J.H. Seinfeld. Development and Application of the Model of Aerosol Dynamics, Reaction, Ionization and Dissolution (MADRID), *J. Geophys. Res.* **2004**, 109, D01202, doi:10.1029/2003JD003501.

[33] Pun, B., C. Seigneur, J. Pankow, R. Griffin, and E. Knipping. An upgraded absorptive secondary organic aerosol partitioning module for three-dimensional air quality applications, 24th Annual American Association for Aerosol Research Conference, Austin, TX, October 17-21, 2005. (2005)

of aqueous-phase SO_2 oxidation chemistry. The KCBB study incorporated into CALPUFF a treatment of sulfate formation in clouds that is based on the treatment that is used in EPA's CMAQ model.

CALPUFF Model Evaluation and Sensitivity Tests

The EPA-approved version of CALPUFF and the version with the improved chemistry options were evaluated using the 1995 Southwest Wyoming Technical Air Forum (SWWYTAF) database[34], available from the Wyoming Department of Environmental Quality. The database includes MM5 output for 1995, CALMET and CALPUFF codes and control files, emissions for the Southwest Wyoming Regional modeling domain, and selected outputs from the CALPUFF simulations. Several sensitivity studies were also conducted to investigate the effect of background NH_3 concentrations on model predictions of PM nitrate. Twice-weekly background NH_3 concentrations were provided from monitoring station observations for the Pinedale, Wyoming area. These data were processed to calculate seasonally averaged background NH_3 concentrations for CALPUFF.

Two versions of CALPUFF with different chemistry modules were evaluated with this database:

1. MESOPUFF II chemistry using the Federal Land Managers' Air Quality Related Values Work Group (FLAG) recommended background NH_3 concentration of 1 ppb for arid land. As discussed previously, the MESOPUFF II algorithm is the basis for the currently approved version of CALPUFF that is being used for BART determinations throughout the United States.

2. Improved CALPUFF RIVAD/ARM3 chemistry using background values of NH_3 concentrations based on measurements in the Pinedale, Wyoming area, as described above.

PM sulfate and nitrate were predicted by the two models and compared with actual measured values obtained at the Bridger Wilderness Area site from the IMPROVE network and the Pinedale site from the Clean Air Status and Trends Network (CASTNET). For the two model configurations evaluated in this study, the results for PM sulfate were very similar, which was expected since the improvements to the CALPUFF chemistry were anticipated to have the most impact on PM nitrate predictions. Therefore, the remaining discussion focuses on the performance of each model with respect to PM nitrate.

The EPA-approved CALPUFF model was found to significantly overpredict PM nitrate concentrations at the two monitoring locations, by a factor of two to three. The performance of the version of CALPUFF with the improved RIVAD chemistry was much better, with an overprediction of about 4% at the Pinedale CASTNET site and of about 28% at the Bridger IMPROVE site.

In an important sensitivity analysis conducted within the KCBB study, both the EPA-approved version of CALPUFF and the improved version were run with a constant ammonia background of 1 ppb, as recommended by IWAQM Phase II[35]. The results were similar to those noted above: the improved

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[34] Wyoming Department of Environmental Quality. 1995 Southwest Wyoming Technical Air Forum (SWWYTAF) database. Background and database description are available at http://deq.state.wy.us/aqd/prop/2003AppF.pdf. (2010)

[35] Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Long-Range Transport Modeling, EPA-454/R-98-019. (1998)

CALPUFF predictions were about two to three times lower than those from the EPA-approved version of CALPUFF. This result is similar to the results using the seasonal observed values of ammonia, and indicates that the sensitivity of the improved CALPUFF model to the ammonia input value is potentially less than that of the current EPA-approved model.

Similar sensitivity was noted by Scire et al. in their original work in the SWWYATF study[36], in which they tested seasonally varying levels of background ammonia in CALPUFF (using 0.23 ppb in winter, for example; see Figure B-3. The sensitivity modeling for predicting levels of nitrate formation shows very similar results to those reported in the KCBB study.

These findings indicate that to compensate for the tendency of the current EPA-approved version of CALPUFF to overpredict nitrates, the background ammonia values that should be used as input in CALPUFF modeling should be representative of isolated areas (e.g., Class I areas).

On November 3, 2010, TRC released a new version (6.42) of CALPUFF to fix certain coding "bugs" in EPA-approved version 5.8 and to improve the chemistry module. Additional enhancements to CALPUFF version 6.42 have been reported at EPA's 10th modeling conference in March 2012 by Scire[37], who also has conducted recent evaluations of this version in comparison to the regulatory version (5.8). Despite the evidence that this CALPUFF version is a generation ahead of the currently approved version for modeling secondary particulate formation, EPA has not acted to adopt it as a guideline model. Even with evidence provided by independent investigators[29,30] that also indicate that wintertime nitrate estimated by CALPUFF version 5.8 is generally overpredicted by a factor between 2 and 4, EPA has not taken steps to adopt the improved CALPUFF model, noting that extensive peer review, evaluations, and rulemaking are still needed for this adoption to occur. In the meantime, EPA, in retaining CALPUFF version 5.8 as the regulatory model for regional haze predictions, is ignoring the gross degree of overestimation of particulate nitrate and is thus ensuring that regional haze modeling conducted for BART is overly conservative. EPA's delay in adopting CALPUFF version 6.42 will thus result in falsely attributing regional haze mitigation to NO_X emission reductions.

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[36] Scire, J.S., Z-X Wu, D.G. Strimaitis and G.E. Moore. The Southwest Wyoming Regional CALPUFF Air Quality Modeling Study – Volume I. Prepared for the Wyoming Dept of Environmental Quality. (2001)

[37] Scire, J., 2012. New Developments and Evaluations of the CALPUFF Model. http://www.epa.gov/ttn/scram/10thmodconf/presentations/3-5-CALPUFF_Improvements_Final.pdf.

OVERPREDICTIONS OF NITRATE HAZE BY REGIONAL PHOTOCHEMICAL MODELS

The overprediction tendency for modeling of wintertime nitrate haze is not limited to CALPUFF. Even the state-of-the-art regional photochemical models are challenged in getting the right ammonium nitrate concentrations. This is evident in a presentation[38] made by Environ to the CENRAP Regional Planning Organization in 2006. The relevant figures from the Ralph Morris presentation (shown in Figures B-4 and B-5 below) indicate that both CMAQ and CAMx significantly overpredict nitrate haze in winter at Voyageurs National Park, by about a factor of 2. This is shown by the height of the red portion of the composition plot stacked bars between the observed and predicted timelines. It is noteworthy that Minnesota and EPA have relied upon this modeling approach for their BART determinations. Similar to CALPUFF, as discussed above, the agency modeling is prone to significantly overpredicting wintertime nitrate haze, leading to an overestimate of visibility improvement with NO_X emission reductions.

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[38] http://pah.cert.ucr.edu/aqm/cenrap/meetings.shtml, under “MPE”, slides 9 and 10.

Figure B-3: Sensitivity Study of Nitrate Predictions at Bridger Wilderness Area for Input Ammonia Concentrations to CALPUFF (0.23, 0.5, and 1.0 ppb).

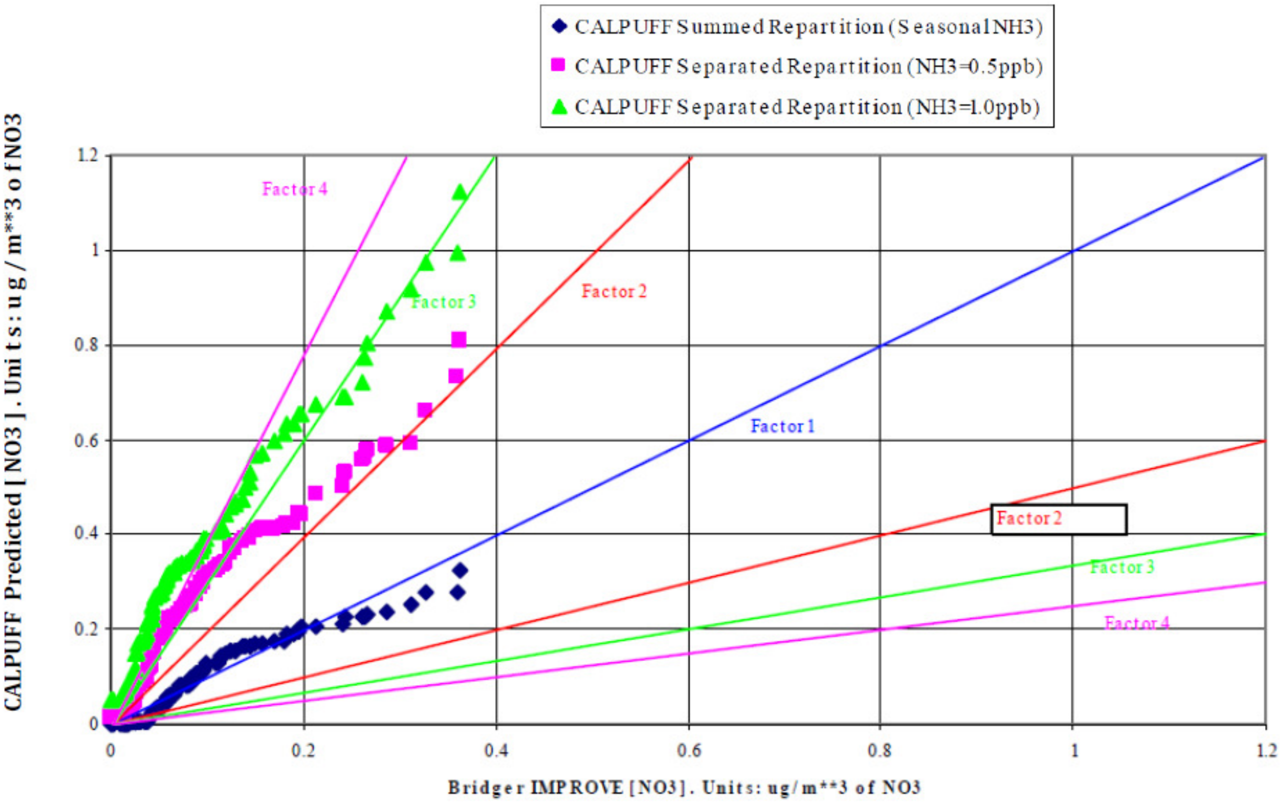


Figure B-4 CMAQ vs. Observed Haze Predictions at Voyageurs National Park

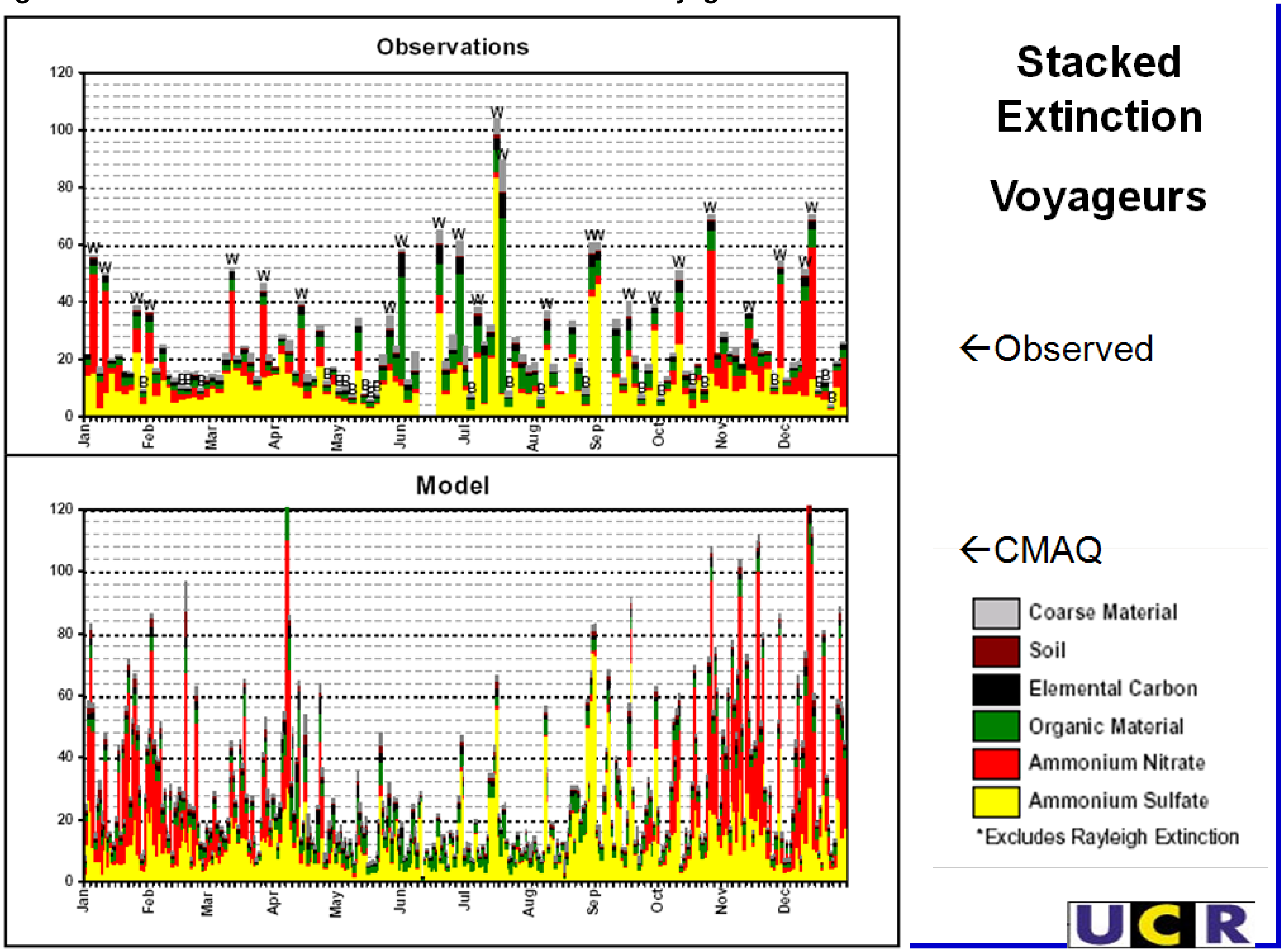
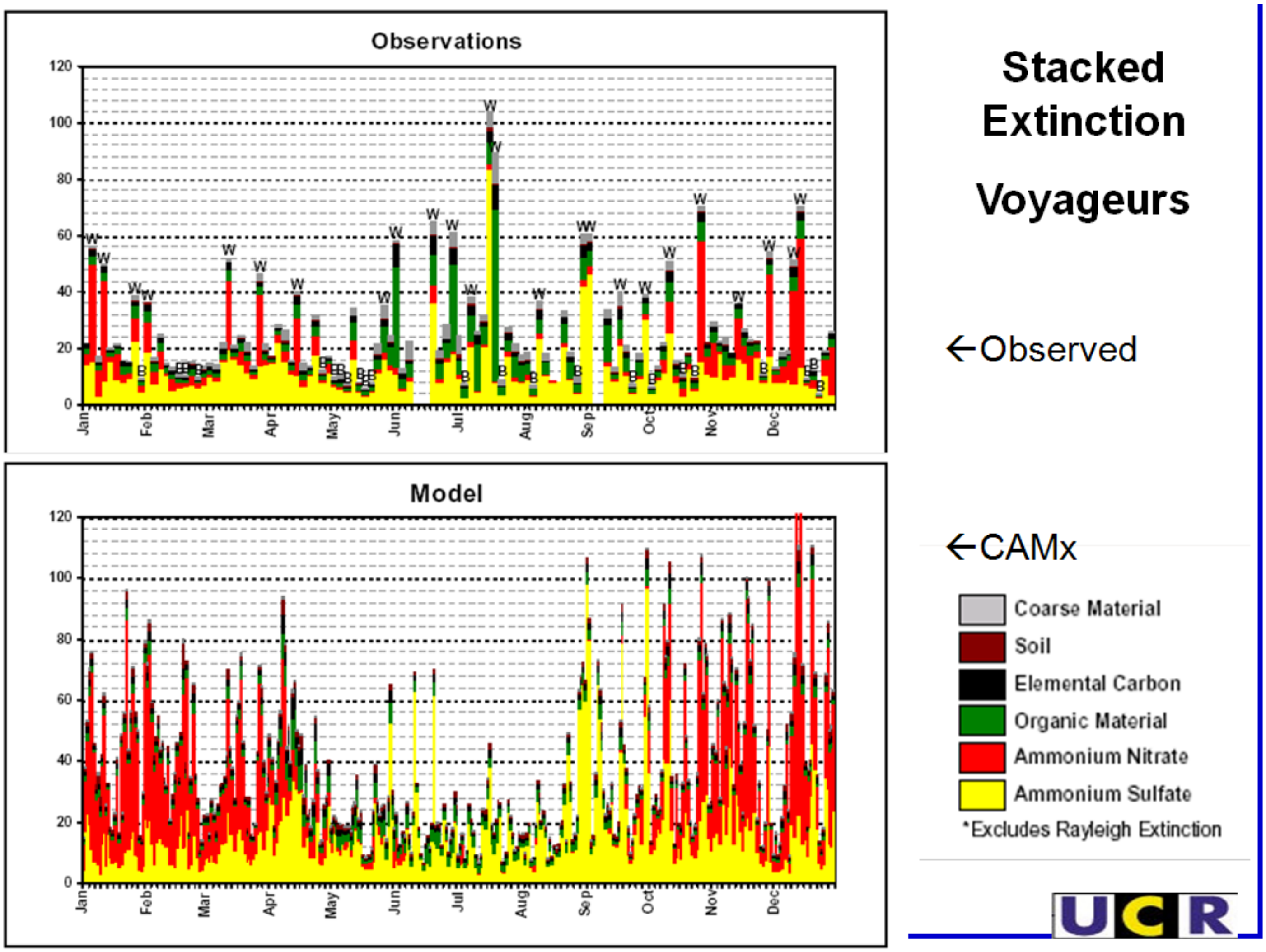


Figure B-5 CAMx vs. Observed Haze Predictions at Voyageurs National Park



APPENDIX C

Haze Time Series Plots for Voyageurs National Park, Seney Wilderness Area, and Isle Royale National Park

Figure C-1 Time Series of Nitrate Haze at Voyageurs National Park (2002-2010)

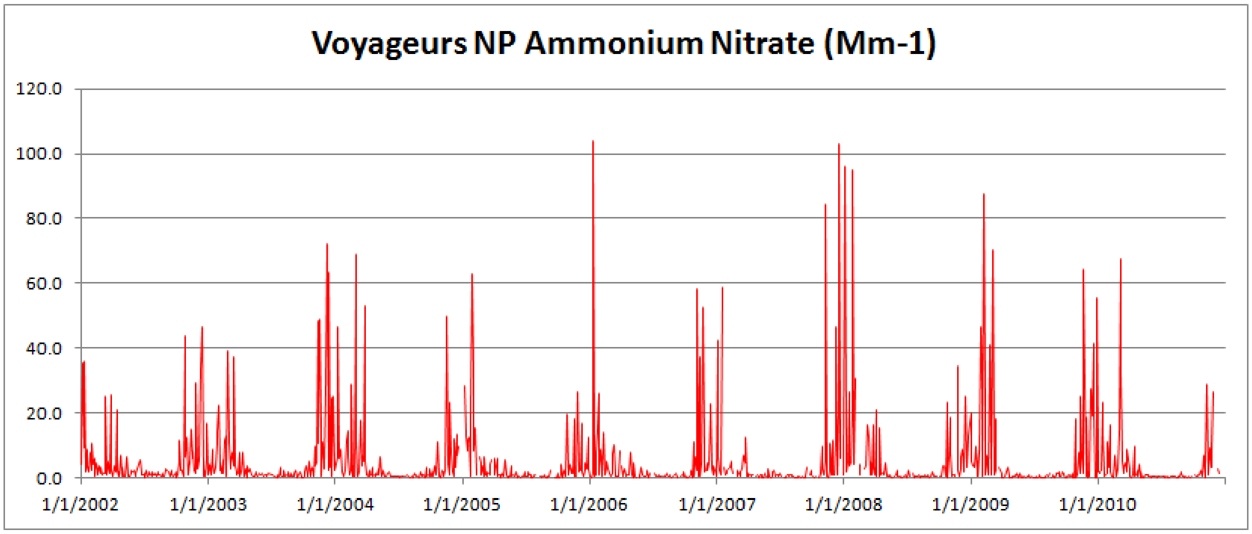


Figure C-2 Time Series of Sulfate Haze at Voyageurs National Park (2002-2010)

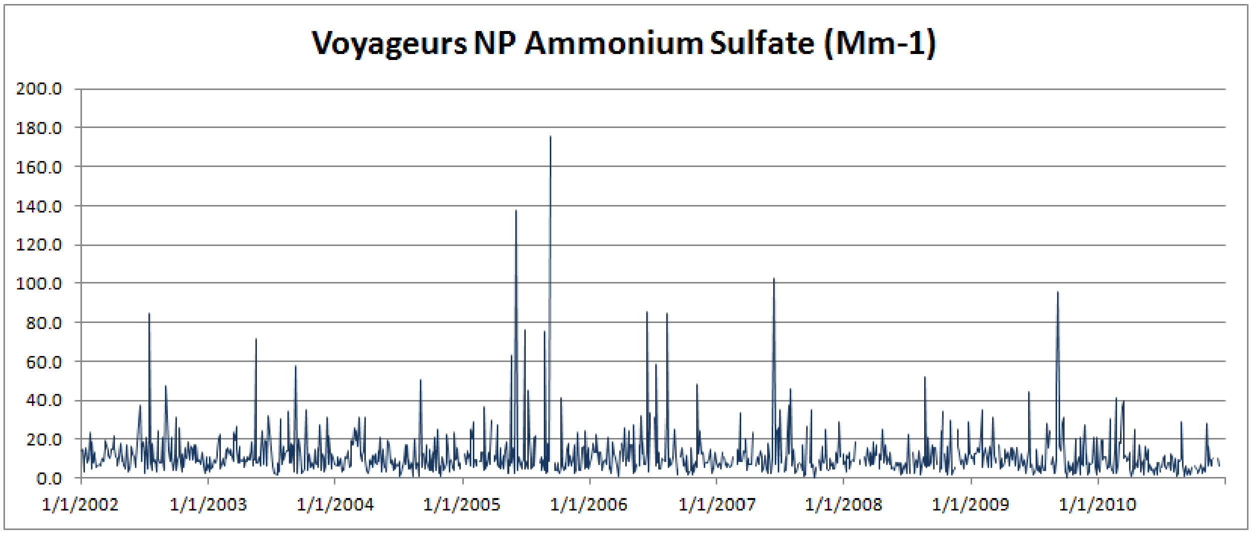


Figure C-3 Time Series of Nitrate Haze at Seney Wilderness Area (2002-2010)

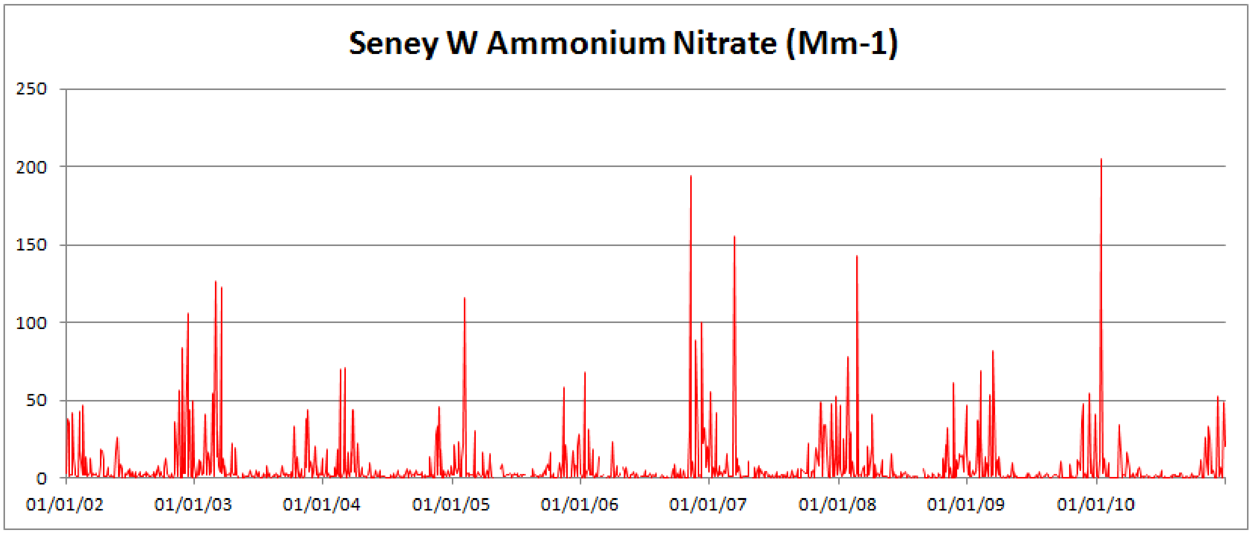


Figure C-4 Time Series of Sulfate Haze at Seney Wilderness Area (2002-2010)

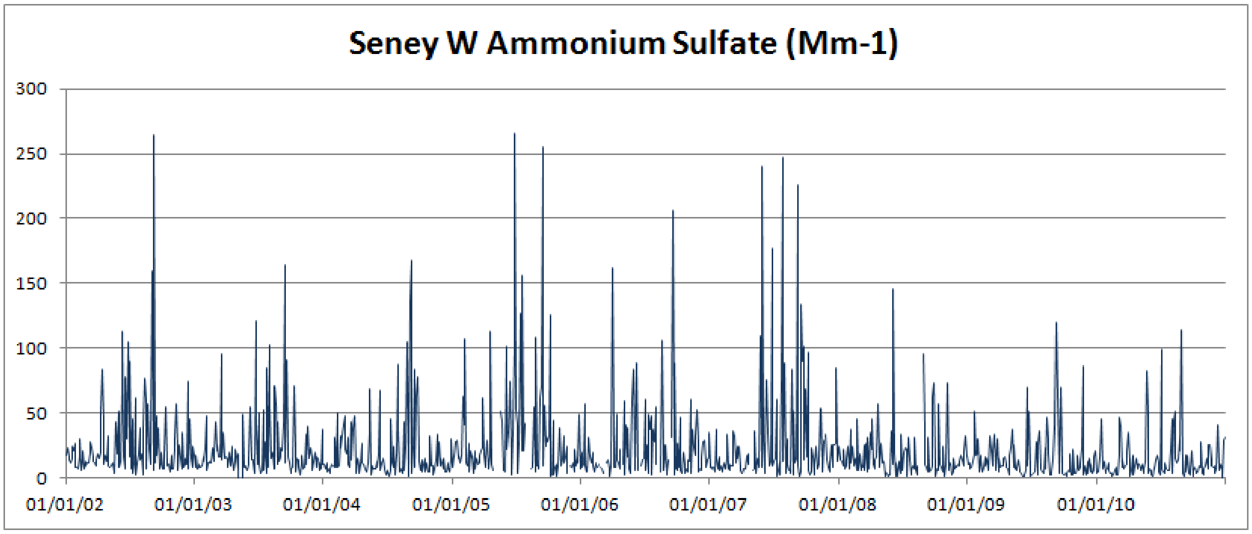


Figure C-5 Time Series of Nitrate Haze at Isle Royale National Park (2002-2010)

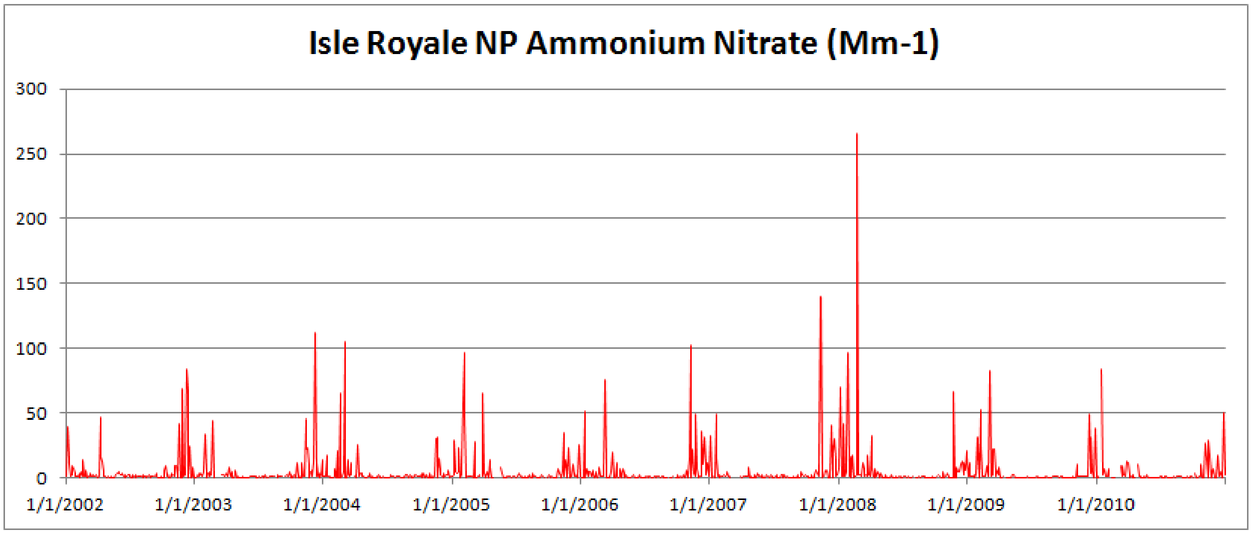
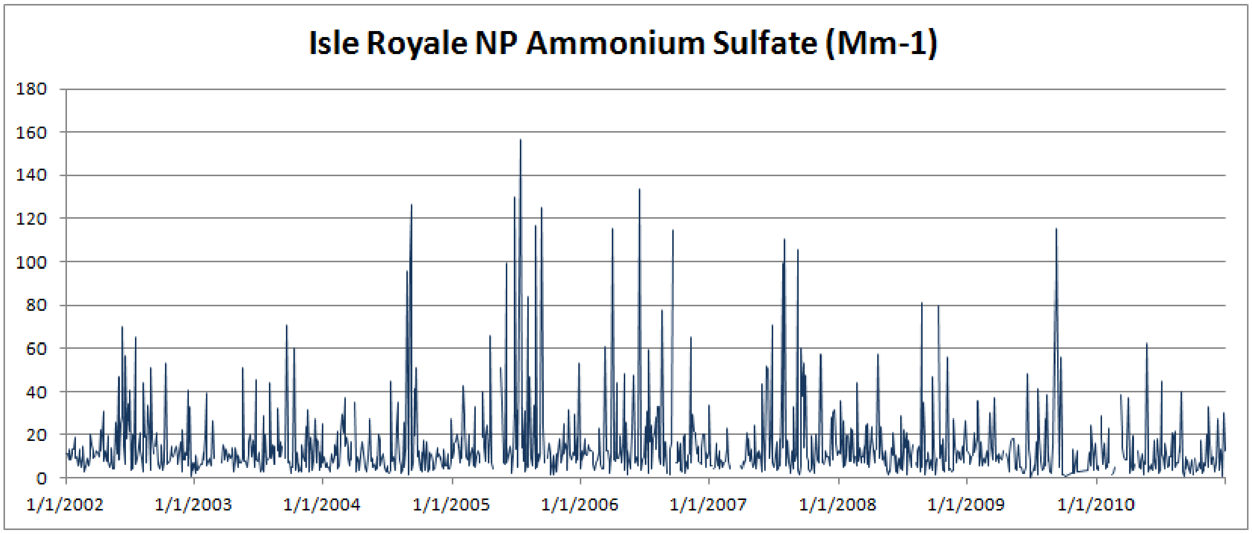


Figure C-6 Time Series of Sulfate Haze at Isle Royale National Park (2002-2010)



APPENDIX D

EXAMPLE OF VISIBILITY CHANGES AFTER ACTUAL EMISSION REDUCTIONS: SHUTDOWN OF THE MOHAVE GENERATING STATION

The Mohave Generating Station (MGS) shut down at the end of 2005, which should have had a large, beneficial effect (over 2 dv, according to CALPUFF) upon Grand Canyon visibility on the 98th percentile worst days. The MGS was a large (1590 MW) coal-fired plant located near the southern tip of Nevada (Laughlin, NV). MGS was placed in operation in the early 1970s, and was retired at the end of 2005 as a result of a consent agreement with the United States Environmental Protection Agency (EPA). The agreement had provided MGS with the option of continued operation if state-of-the-art emissions controls were installed for SO_2 and NOx emissions, but the owners determined that the cost of controls was too high to justify the investment. As a result, the plant was shut down on December 31, 2005 and has not been in operation since then.

As shown in Figure C-1, the MGS location is about 115 km away from the closest point of the Grand Canyon National Park, for which a southwesterly wind is needed to carry the emissions from MGS to most of the park. A multi-year study[39] completed by the EPA in 1999 (Project MOHAVE) indicated that MGS could be a significant contributor to haze in the Grand Canyon. In fact, typical annual emissions from MGS during the last several years of operation were approximately 40,000 tons per year (TPY) of SO_2 and 20,000 TPY of NOx. EPA noted in their Project MOHAVE conclusions that due to this level of emissions of haze precursors and its proximity to the Grand Canyon, MGS was the single largest emission source that could cause regional haze within the Grand Canyon.

Haze observations at three locations in the Grand Canyon (Meadview, Indian Garden, and Hance Camp monitors are available every third day for periods both before and after the plant shut down at the end of 2005. By comparing haze measurements before and after plant shutdown, it may be possible to determine whether the haze in the Grand Canyon has perceptibly changed since 2005 by reviewing the data from these three monitors. The Meadview monitor is at the western edge of the Park, and is relatively close to MGS. The other two IMPROVE monitors are located near some of the most heavily visited areas of the park (Hance Camp, on the South Rim, and Indian Garden, about 1,100 feet lower near the bottom of the canyon).

A 2010 *Atmospheric Environment* paper by Terhorst and Berkman[40] studied the effects of the opportunistic "experiment" afforded by the abrupt shutdown of the largest source affecting the Grand Canyon (according to EPA). The paper noted that Project MOHAVE's conclusions about the effects of MGS on the Grand Canyon visibility were ambiguous. The project's tracer studies revealed that while the MGS emissions did reach the park, particularly in the summer, there was no evidence linking these elevated concentrations with actual visibility impairment; indeed, "correlation between measured tracer concentration and both particulate sulfur and light extinction were virtually nil."

On the other hand, dispersion models produced results inconsistent with the observations. Noting the disconnect between the measurements and model predictions, EPA noted the disparity between the measurements and modeling results, but still appeared to favor the models when it concluded that MGS was the largest sole contributor to visibility impairment in the Grand Canyon.

---

[39] Pitchford, M., Green, M., Kuhns, H., Scruggs, M., Tombach, I., Malm, W., Farber, R., Mirabella, V., 1999. Project MOHAVE: Final Report. Tech. Rep., U.S. Environmental Protection Agency (EPA).

[40] Jonathan Terhorst and Mark Berkman. "Effect of Coal-Fired Power Generation on Visibility in a Nearby National Park," Atmospheric Environment, 44(2010) 2544-2531. This publication is available by request from Mark Berkman at mark.berkman@berkeleyeconomics.com.

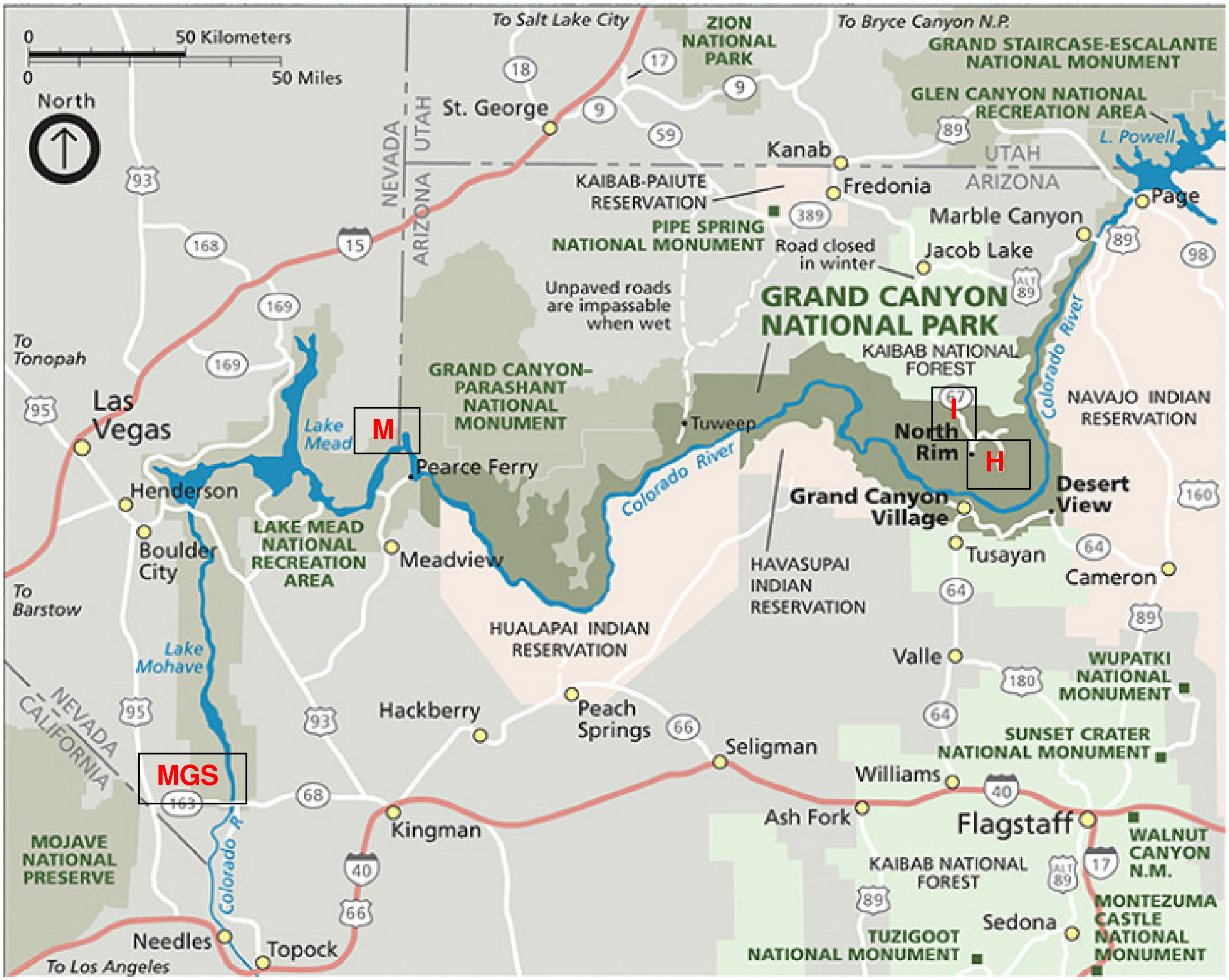
According to the authors, the Project Mohave observations were consistent with observations during temporary outages of MGS, for which there were no reports of substantial changes to visibility in the Grand Canyon.

Best Available Retrofit Technology (BART) studies evaluated a possible conversion of MGS to natural gas firing in 2008. These studies used the CALPUFF dispersion model in a manner prescribed by EPA to determine the change in visibility between the baseline emissions associated with coal firing to the natural gas firing alternative. The BART analyses conducted by the Nevada Department of Environmental Protection indicated that large differences in haze would result: an improvement of about 2.4 deciviews for the 98th percentile peak day, and a haze reduction to below 0.5 deciview on 186 days over 3 years modeled. Since natural gas firing would eliminate nearly all of the SO_2 emissions (although not all of the NOx emissions) this modeled result would tend to underestimate the visibility improvement that would be anticipated with a total plant shutdown.

Terhorst and Berkman analyzed several statistics to determine the change in sulfate concentrations and visibility in the Grand Canyon between the period 2003-2005 (pre-shutdown) and the period 2006-2008 (post-shutdown). They also considered other areas to determine how other regional and environmental effects might be reflected in changes at the Grand Canyon. Terhorst and Berkman calculated the average visibility over all IMPROVE monitoring days between 2003-2005 and 2006-2008, and determined that the average visibility was unchanged at Meadview, slightly improved on the South Rim (Hance Camp), and slightly worse at Indian Garden. Consistent with the observations of minimal visibility impact of MGS during Project MOHAVE, they concluded that the closure of MGS had a relatively minor effect on visibility in the Grand Canyon. These authors questioned the veracity of CALPUFF modeling (e.g., for BART) in that it predicts relatively large improvements in the Grand Canyon visibility that are not borne out by observations.

Emissions reductions associated with the shutdown of the Mohave Generating Station at the end of 2005 have provided an opportunistic means to discern the effect of retrofitting emission controls on coal-fired power plants in the western United States. In the case of MGS, although EPA had determined that this facility was the single most important contributor to haze in the Grand Canyon National Park and CALPUFF modeling using EPA's BART procedures provided predictions of significant improvements in haze, actual particulate and haze measurements taken before and after the shutdown do not reflect the large reductions that would be anticipated from these studies. This may be due in part to the fact that there are several aspects to the CALPUFF modeling procedures that greatly inflate the predicted haze (as noted below), and therefore, the predicted improvements due to emission reductions.

Figure D-1 : Map Showing the Relationship of the Mohave Generating Station to the Grand Canyon National Park



http://www.nps.gov/grca/planyourvisit/upload/GRCAmap2.pdf

H: Hance Camp monitor

I: Indian Garden monitor

M: Meadview monitor

From: Zavoda, Rich
To: Bouchareb, Hassan (MPCA); Seelen, Sarah (MPCA)
Cc: Johnson, Jaime; Peterson, Robb A; Machinal, Mandy L; Latendresse, Edward M; Lucas, Julie C; Niemi, Tasha M; Ekholm, Corie A; Ryan D. Siats; Kurdila, Julianne; Zavoda, Rich
Subject: FW: Minnesota Regional Haze Update :: Source Selection & Four Factor Analysis :: ArcelorMittal Minorca and Hibbing Taconite Company
Date: Wednesday, July 1, 2020 12:43:50 PM
Attachments: MPCA NOx SOx 2016 2028 w Corrected NOx 2028 for LNBs installed 7.1.20.xlsx
Minorca Mine SO2 Limit Revision for FIP 4.6.2018.pdf
4.11.18 HTC FIP SO2 Limit Reset Request.pdf
RE Regional Haze ArcelorMittal (HibbingMinorca) Four Factor Analyses H. Bouchareb x2653 Post.msg

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Hassan

As a follow-up to the Hibbing and Minorca “Four Factor Analysis” Reports submitted to MPCA on 5/29/20 and our request that both facilities be considered “Effectively Controlled” based on the newly engineered site specific Low NOx Burner Technology that has already been installed on all four natural gas pellet lines as discussed during our 6/12/20 conference call, please see the attached documentation of the reduction of NOx emissions.

The attached excel file provides requested NOx reduction data analysis and production records in three worksheets. The attached data provides the MPCA proposed 2016 Baseline and 2028 projections of NOx and SO2 tpy estimates that need to be corrected to account for the NOx reduction technology already installed on all four lines (Hibbing’s 3 lines and Minorca’s furnace). The data analysis also provide the 2017 NOx and SO2 tpy emissions based on a full year of CEMs data and is recommended to be used as a more accurate baseline compared to the 2016 estimates. The data highlights the incorrect NOx data in red font and uses blue font for the recommended 2017 Baseline and Corrected 2028 projections of NOx and SO2 tpy estimates. The corrected data is requested to be used for any LADCO modeling.

Per your request, the SO2 CEMs 95 percentile Upper Predictive Limit (UPL) statistical analysis reports as specified by the BART FIP requirements are attached. The reports for the natural gas fired indurating furnaces are dated 4/6/18 for Minorca and 4/11/18 for Hibbing. These reports that were submitted to USEPA provide the 95 UPL technical justification including one year of CEMs data for the respective SO2 lb/hr 30-day rolling average UPL rates referenced in the 5/29/20 “Four Factor Analysis” (page 21) for both facilities: 58.64 lb/hr for Minorca (see pdf pages 2 and 9) and 279.3 lb/hr for Hibbing (see pdf pages 3 and 4). The actual SO2 emissions from the natural gas fired pellet furnaces at Minorca and Hibbing have consistently complied with the respective lb/hr 30 day average 95 UPL rates referenced in the May 29, 2020 “Four Factor Analysis” reports.

Please let us know if you have any questions or would like to discuss. We look forward to the agency’s response to our 5/29/20 Four Factor Analysis” Reports. Thanks again for your assistance with this important issue.

Rich Zavoda | Regional Manager, Air Quality Program
ArcelorMittal USA
Environmental Affairs| 4020 Kinross Lakes Parkway, Richfield, Ohio 44286-9000
T +1 330 659 9163 | F +1 330 659 7434 | www.arcelormittal.com

From: Johnson, Jaime <Jaime.Johnson@arcelormittal.com>
Sent: Tuesday, June 2, 2020 2:09 PM
To: Bouchareb, Hassan (MPCA) <hassan.bouchareb@state.mn.us>
Cc: Zavoda, Rich <Rich.Zavoda@arcelormittal.com>; Peterson, Robb A <robb.peterson@arcelormittal.com>; Machinal, Mandy L <mandy.machinal@arcelormittal.com>; Latendresse, Edward M <edward.latendresse@arcelormittal.com>; Lucas, Julie C <julie.lucas@arcelormittal.com>; Niemi, Tasha M <tasha.niemi@arcelormittal.com>; Ryan D. Siats <RSiats@barr.com>

Subject: RE: Minnesota Regional Haze Update :: Source Selection & Four Factor Analysis :: ArcelorMittal Minorca

Hassan,

Good morning. ArcelorMittal Hibbing and Minorca facilities, (facilities) received MPCA's Request for Information letter dated January 29, 2020. This letter requested the facilities prepare a Four Factor Analysis for the indurating machine(s). These analyses are to be prepared using the August 20, 2019 U.S. Environmental Protection Agency guidance that provides recommendations for how each of the factors should be analyzed. However, the Guidance also provides flexibility to the state such that states are not required to evaluate *all* sources of emissions in each implementation period. Instead, a state may select a set of sources for analysis of control measures and reasonably exclude others from the analysis.

The facilities' indurating machine(s) meet the BART required control equipment scenarios and are effectively controlled source(s) for NOx and SO2. BART emission controls and emission limits for NOX and SO2 are determined pursuant to 40 CFR 52.1235(b)(1) and 52.1235(b)(2), respectively. In accordance with the April 12, 2016 FIP, the Facilities timely implemented the BART NOx control measures by installing and operating newly engineered site-specific Low NOx Burner technology on all four pellet lines (three at Hibbing and one at Minorca) prior to the required FIP compliance dates with three of the four lines completing installation in 2020. The indurating machines are subject to the FIP NOx emission limits as defined in the FIP. The indurating furnace Low NOx Burners recently installed have reduced the majority of the NOx emissions. In the FIP preamble, U.S. EPA concluded that BART for SO2 emissions from these natural gas fired lines, already equipped with Taconite MACT wet scrubbers, is existing controls. Thus, each of the indurating machines is considered an "effectively controlled source" in accordance with the 2019 U.S. EPA Guidance and may be reasonably excluded from the requirement to prepare and submit a four-factor analysis.

ArcelorMittal would like to request a call with you to discuss the submitted report which indicates that the sources at the Facilities are effectively controlled for the purpose of this implementation period. Understanding that this process is time sensitive for the MPCA and the Facilities, ArcelorMittal prefers to have this call with representatives from ArcelorMittal USA, Minorca, Hibbing and Barr Engineering. We are proposing the following date/times for a call:

Availability

Monday 6/8/2020	12:00pm-1:00pm
Tuesday 6/11/2020	11:00am – 12:00pm
	2:00pm-3:00pm
Friday 6/12/2020	10:00 – 11:00am
	12:00-1:00pm

I thank you for your time and consideration of this request. I look forward to hearing from you in the near future to further our discussions on the request submitted on the 29th of May.

Thank you,
Jaime

Jaime L. Johnson
Manager - Environmental

ArcelorMittal Minorca Mine Inc.
5950 Old U.S. Highway 53 | Virginia, MN 55792
T +1 218 305 3337 | F +1 218 749 5256
www.arcelormittal.com

"Wrinkles only go where the smiles have been" – Jimmy Buffett

"Happiness cannot be traveled to, owned, earned, worn, or consumed. Happiness is a spiritual experience of living every minute with love, grace, and gratitude" - Dennis Waitley

"I believe that imagination is stronger than knowledge - myth is more potent than history - dreams are more powerful than facts - hopes always triumphs over experience - laughter is the cure for grief - love is stronger than death" - Robert Fulghum

---

From: Bouchareb, Hassan (MPCA) <hassan.bouchareb@state.mn.us>
Sent: Friday, May 29, 2020 12:46 PM
To: Machinal, Mandy L <mandy.machinal@arcelormittal.com>
Cc: Seelen, Sarah (MPCA) <sarah.seelen@state.mn.us>; deAlwis, Deepa (MPCA) <deepa.dealwis@state.mn.us>; Boeck, Cory (MPCA) <cory.boeck@state.mn.us>; Kohlasch, Frank (MPCA) <frank.kohlasch@state.mn.us>; Zavoda, Rich <Rich.Zavoda@arcelormittal.com>; Peterson, Robb A <robb.peterson@arcelormittal.com>; Johnson, Jaime <Jaime.Johnson@arcelormittal.com>
Subject: RE: Minnesota Regional Haze Update :: Source Selection & Four Factor Analysis :: ArcelorMittal Minorca

This Message originated from a Non-ArcelorMittal source

Good afternoon Mandy,

Thank you for sending this information. I'll review the response and let you know if I have any questions.

Thank you!

Hassan M. Bouchareb | Engineer
Minnesota Pollution Control Agency (MPCA)
Office: (651) 757-2653 | Fax: (651) 296-8324
Pronouns: he/him/his
Hassan.Bouchareb@state.mn.us | www.pca.state.mn.us

From: Machinal, Mandy L <mandy.machinal@arcelormittal.com>
Sent: Friday, May 29, 2020 12:25 PM
To: Bouchareb, Hassan (MPCA) <hassan.bouchareb@state.mn.us>
Cc: Seelen, Sarah (MPCA) <sarah.seelen@state.mn.us>; deAlwis, Deepa (MPCA) <deepa.dealwis@state.mn.us>; Boeck, Cory (MPCA) <cory.boeck@state.mn.us>; Kohlasch, Frank (MPCA) <frank.kohlasch@state.mn.us>; Zavoda, Rich <Rich.Zavoda@arcelormittal.com>; Peterson, Robb A <robb.peterson@arcelormittal.com>; Johnson, Jaime <Jaime.Johnson@arcelormittal.com>
Subject: Minnesota Regional Haze Update :: Source Selection & Four Factor Analysis :: ArcelorMittal Minorca

---

Good Afternoon –

Please see Minorca's attached response to MPCA's request for information for the Four Factor Analysis. We look forward to MPCA's timely response on this submittal.

Thank you,
Mandy Machinal

Mandy Machinal | Engineer - Environmental
ArcelorMittal Minorca
Iron Mining | 5950 Old U.S. Highway 53 | PO Box 1
Virginia, MN 55792 USA

T +1 218-305-3425 **|** **F** +1 218 749 3397 | **E** Mandy.Machinal@arcelormittal.com

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CONTROL AGENCY

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800-657-3864 | Use your preferred relay service | info.pca@state.mn.us | Equal Opportunity Employer

January 29, 2020

Andrea Hayden, Environmental Manager
Northshore Mining Company
10 Outer Drive
Silver Bay, MN 55614

RE: Request for Information - Regional Haze Rule, Reasonable Progress, Four Factor Analysis

Dear Ms. Hayden:

The Minnesota Pollution Control Agency (MPCA) is currently preparing information for the second planning period (Round 2) comprehensive update to Minnesota's Regional Haze State Implementation Plan (SIP) as required by the Regional Haze Rule (40 CFR § 51.308). States are responsible for developing a Regional Haze SIP that addresses regional haze in each Class I area located within the state and in each Class I area located outside the state which may be affected by emissions from sources within the state. The Regional Haze SIP is required to identify existing facilities that cause or contribute to visibility impairment; analyze, identify, and apply federally-enforceable control strategies for those sources; and periodically demonstrate reasonable progress toward reaching visibility goals. States are also responsible for periodic comprehensive updates to their Regional Haze SIP that address these same topics. Minnesota's Round 2 Regional Haze SIP must be submitted to the U.S. Environmental Protection Agency (U.S. EPA) by July 31, 2021.

Minnesota has two Class I areas within its borders, the Boundary Waters Canoe Area Wilderness (BWCA) and Voyageurs National Park (Voyageurs). Other nearby Class I areas include Isle Royale National Park in Michigan. Therefore, Minnesota must prepare a Regional Haze SIP that identifies sources that cause or contribute to visibility impairment in these areas. To meet the core requirements for regional haze for these areas, Minnesota must submit a SIP that contains the plan elements and supporting documentation for all required analyses identified in 40 CFR § 51.308(f).

In the first planning period (Round 1), the focus of the Regional Haze Rule was on establishing Best Available Retrofit Technology (BART) for certain older sources and reasonable progress towards national visibility goals. In Round 2, there are no BART requirements; therefore, the focus is on making reasonable progress. The U.S. Environmental Protection agency has defined the methodology that states must use to determine what measures are necessary to make reasonable progress in 40 CFR § 51.308(f)(2). At minimum, the reasonable progress analysis must use the four factors identified in 40 CFR § 51.308(f)(2)(i) to evaluate and determine the emission reduction measures necessary to make reasonable progress. The four factors are:

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

Data from the IMPROVE monitoring sites at BWCA and Voyageurs indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X).

You are receiving this letter because your facility was identified as a significant source of NO_X and SO_2 and is located close enough to the BWCA or Voyageurs to potentially cause or contribute to visibility impairment in these Class I areas. Therefore, the MPCA requests that you prepare a "Four Factor Analysis" for the following emission units:

1. Power Boiler 1 (EQUI 14 / EU 001) that addresses emissions of NO_X and SO_2
2. Power Boiler 2 (EQUI 15 / EU 002) that addresses emissions of NO_X and SO_2

The analysis should be prepared using the U.S. Environmental Protection Agency guidance[1] that provides recommendations for how each of the factors should be determined.

Preparation of the comprehensive update to Minnesota's Regional Haze SIP will require extensive planning and review of sources in Minnesota. The MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to prepare the Regional Haze SIP. The MPCA expects air quality modeling of potential regional emissions reductions will be conducted beginning in spring 2020. I appreciate your attention to this matter and request that you **submit the Four Factor Analysis by July 31, 2020**.

If you have any questions regarding this matter, or would like to request a meeting to further discuss the contents of this letter, please contact me by phone at 651-757-2653 or by email at Hassan.Bouchareb@state.mn.us.

Sincerely,

Hassan Bouchareb

This document has been electronically signed.

Hassan M. Bouchareb
Engineer
Environmental Analysis and Outcomes Division

Cc: Paul Carlson, Northshore Mining Company
Jennifer Ramsdell, Northshore Mining Company
Jason Aagenes, Cleveland-Cliffs Inc.
Scott Gischia, Cleveland-Cliffs Inc.
Deepa de Alwis, MPCA
Cory Boeck, MPCA
Frank Kohlasch, MPCA
Agency Interest ID 1875

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[1] **U.S. Environmental Protection Agency.** *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 20, 2019, https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

Address questions and submittals requested above to:

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February 24, 2020

Andrea Hayden, Environmental Manager
Northshore Mining Company
10 Outer Drive
Silver Bay, MN 55614

RE: Request for Information - Regional Haze Rule, Reasonable Progress, Four Factor Analysis

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Data from the IMPROVE monitoring sites at BWCA and Voyageurs indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X).

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1. Power Boiler 1 (EQUI 14 / EU 001) that addresses emissions of NO_X and SO_2
2. Power Boiler 2 (EQUI 15 / EU 002) that addresses emissions of NO_X and SO_2
3. Furnace 11 (EQUI 126 & 127 / EU 100 & 104) that addresses emissions of NO_X and SO_2
4. Furnace 12 (EQUI 128 & 129 / EU 110 & 114) that addresses emissions of NO_X and SO_2

The analysis should be prepared using the U.S. Environmental Protection Agency guidance[1] that provides recommendations for how each of the factors should be determined.

Preparation of the comprehensive update to Minnesota's Regional Haze SIP will require extensive planning and review of sources in Minnesota. The MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to prepare the Regional Haze SIP. The MPCA expects air quality modeling of potential regional emissions reductions will be conducted beginning in spring 2020. I appreciate your attention to this matter and request that you **submit the Four Factor Analysis by July 31, 2020**.

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Regional Haze Four-Factor Analysis for NO_X and SO_2 Emissions Control

Power Boiler 1 EQUI 14/EU 001

Power Boiler 2 EQUI 15/EU 002

Prepared for
Northshore Mining Company

July 31, 2020

Regional Haze Four-Factor Analysis for NO_X and SO_2 Emissions Control

Power Boiler 1 EQUI 14/EU 001

Power Boiler 2 EQUI 15/EU 002

Prepared for
Northshore Mining Company

July 31, 2020

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Regional Haze Four-Factor Analysis for NO_X and SO_2 Emissions Control

Power Boiler 1 and Power Boiler 2

July 31, 2020

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Abbreviations

BART	Best Available Retrofit Technology
BWCA	Boundary Waters Canoe Area
CAIR	Clean Air Interstate Rule
CEPCI	Chemical Engineering Plant Cost Index
CPI	Consumer Price Index
CSAPR	Cross-State Air Pollution Rule
D.C.	District of Colombia
DSI	Dry Sorbent Injection
EGU	Electric Generating Units
EPA	U.S. Environmental Protection Agency
IMPROVE	Interagency Monitoring of Protected Visual Environments
Isle Royale	Isle Royale National Park
LADCO	Lake Michigan Air Directors Consortium
Lb	Pound
LNB	Low-NO_X Burners
MPCA	Minnesota Pollution Control Agency
NO	Nitric Oxide
NO_X	Nitrogen Oxides
Northshore	Northshore Mining Company
OFA	Overfire Air
O&M	Operating and Maintenance
PSD	Prevention of Significant Deterioration
RFI	Request for Information
RH	Regional Haze
RHR	Regional Haze Rule
SCR	Selective Catalytic Reduction
SDA	Spray Dryer Absorber
SIP	State Implementation Plan
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
tpy	Tons Per Year
TVOP	Title V Operating Permit
Voyageurs	Voyageurs National Park
U.S.	United States
WWESP	Wet Walled Electrostatic Precipitator

1 Executive Summary

In accordance with Minnesota Pollution Control Agency's (MPCA's) February 24, 2020 Request for Information (RFI) Letter[1], Northshore Mining Company (Northshore) evaluated potential emissions control measures for sulfur dioxide (SO_2) and nitrogen oxides (NO_X) for Power Boilers 1 (EQUI 14/ EU001) and 2 (EQUI 15/EU002) as part of the state's Regional Haze Rule (RHR)[2] reasonable progress. The analysis considers potential emissions control measures by addressing the four statutory factors laid out in 40 CFR 51.308(f)(2)(i) and pursuant to the final U.S. Environmental Protection Agency (EPA) RHR State Implementation Plan (SIP) guidance[3] on August 20, 2019 (2019 RH SIP Guidance):

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

This report describes the background and analysis for responding to the RFI and conducting the Four-Factor Analysis for NO_X and SO_2 as applied to the review of emissions controls for the Power Boilers at Northshore. The Four-Factor Analysis conclusions are summarized in Table 1-1 and Table 1-2 for NO_X and SO_2, respectively.

The NO_X Four-Factor Analysis evaluated the following NO_X emissions control measures for the Power Boilers:

- Low NOx burners with overfire air (LNB-OFA); for Power Boiler 2 only
- Selective non-catalytic reduction (SNCR)
- Selective catalytic reduction (SCR)

In the Factor #1 – Cost of Compliance analysis, the associated cost effectiveness ($ for each ton of emissions reduction) for each of the evaluated measures is indeterminate because the projected NOx emissions for 2028 are zero, and accordingly there are no expected additional reductions from any of the potential control technologies (refer to Sections 4.2 and 5.2 and Appendices A and B for more control cost information). Therefore, Northshore's existing NO_X emission performance (refer to Section 3 for more information) is sufficient for the MPCA's regional haze reasonable progress goal.

---

[1] February 24, 2020 letter from Hassan Bouchareb of MPCA to Andrea Hayden of Northshore Mining Company.
[2] The U.S. Environmental Protection Agency (EPA) also refers to this regulation as the Clean Air Visibility Rule. The regional haze program requirements are promulgated at 40 CFR 51.308. The SIP requirements for this implementation period are specified in §51.308(f).
[3] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003.

The SO_2 Four-Factor Analysis evaluated the following SO_2 emissions control measures for the Power Boilers:

- Dry sorbent injection (DSI) with new baghouses
- Spray dryer absorption (SDA) with new baghouses

In the Factor #1 – Cost of Compliance analysis, the associated cost effectiveness ($ for each ton of emissions reduction) for each of the evaluated measures is indeterminate because the projected SO_2 emissions for 2028 are zero, and accordingly there are no expected additional reductions from any of the potential control technologies (refer to Sections 4.2 and 6.2 and Appendices A and B for more control cost information). The Power Boilers SO_2 emissions are minimized by coal pre-processing. Therefore, Northshore's existing SO_2 emission performance (refer to Section 3 for more information) is sufficient for the MPCA's regional haze reasonable progress goal.

In addition to the four statutory factors, states have the discretion to consider any potential visibility improvements if Northshore were to implement the emission control measures, which is referred to as the "fifth factor." Northshore continues to evaluate visibility benefits associated with possible NO_x and SO_2 control measures internally and reserves the right to supplement this analysis with information related to visibility benefits. Northshore plans to conduct CAMx modeling after modeling information from the Lake Michigan Air Directors Consortium (LADCO) is available.

Table 1-1 Summary of NO_X Four-Factor Analysis

List of Emission Control Measure	Factor #1 Cost of Compliance			Factor #2 Time Necessary for Compliance	Factor #3 Energy and Non Air Quality Environmental Impacts of Compliance	Factor #4 Remaining Useful Life of the Source	Does this Analysis Support the Installation of this Emission Control Measure?
	Installed Capital Cost ($)	Annualized Operating Cost ($/year)	Pollution Control Cost ($/ton)				
LNB-OFA (Power Boiler 2 only)	$11,609,362	$1,725,870	NA – See Section 3.2	5 years after SIP promulgation. See Section 5.3.	Environmental Increased carbon monoxide emissions, loss of efficiency, and likely Prevention of Significant Deterioration (PSD) permitting implications. Potential for increased steam tube damage and maintenance due to flame impingement on tubes. Increased maintenance due to scale build-up and corrosion.	20 years control equipment life	No
SNCR	$7,239,275 for Power Boiler 1 $8,917,925 for Power Boiler 2	$992,019 for Power Boiler 1 $1,435,176 for Power Boiler 2	NA – See Section 3.2	5 years after SIP promulgation. See Section 5.3.	Energy Increased energy use to overcome the increased differential pressure. Increased water use for reagent dilution. Increased fuel usage for vaporization of the water in the reagent solution. Environmental Increased ammonia emissions from ammonia slip, which contributes to regional haze. Additional ammonia reacts with sulfates causing increased visibility impairment pollutants.	20 years control equipment life	No

List of Emission Control Measure	Factor #1 Cost of Compliance			Factor #2 Time Necessary for Compliance	Factor #3 Energy and Non Air Quality Environmental Impacts of Compliance	Factor #4 Remaining Useful Life of the Source	Does this Analysis Support the Installation of this Emission Control Measure?
	Installed Capital Cost ($)	Annualized Operating Cost ($/year)	Pollution Control Cost ($/ton)				
					Ammonia emissions will increase condensable PM emissions that will have possible PSD permitting implications. Loss of fly ash re-use. Nitrogen deposition onto nearby lakes and waters of the state will contribute nutrients and to undesirable biological growth. Additional safety and regulatory concerns associated with ammonia or urea storage on site.		
SCR	$40,647,490 for Power Boiler 1 $55,724,684 for Power Boiler 2	$4,159,366 for Power Boiler 1 $5,985,367 for Power Boiler 2	NA – See Section 3.2	5 years after SIP promulgation. See Section 5.3.	<u>Energy</u> Increased energy use to overcome the increased differential pressure. Electricity is required for the SCR equipment, to vaporize the aqueous ammonia reagent. <u>Environmental</u> Increased ammonia emissions from ammonia slip.	20 years control equipment life	No

List of Emission Control Measure	Factor #1 Cost of Compliance			Factor #2 Time Necessary for Compliance	Factor #3 Energy and Non Air Quality Environmental Impacts of Compliance	Factor #4 Remaining Useful Life of the Source	Does this Analysis Support the Installation of this Emission Control Measure?
	Installed Capital Cost ($)	Annualized Operating Cost ($/year)	Pollution Control Cost ($/ton)				
					Ammonium would combine with NOx and SO_2 to form ammonia salts, which would be emitted to the atmosphere as PM_{10}. Emissions of ammonia, ammonium sulfates, and sulfuric acid mist increase plume visibility and contribute to regional haze. Sulfuric acid mist emissions will increase due to the oxidation of SO_2 to SO_3 by the SCR catalyst. Loss of fly ash re-use. Increased oxidized mercury emissions. Nitrogen deposition onto nearby lakes and waters of the state will contribute nutrients and to undesirable biological growth. There are safety risks associated with the transportation, handling, and storage of aqueous ammonia or urea. Spent catalyst from the SCR is typically disposed of in a landfill; however, catalyst recycling or reconditioning may be available.		

Table 1-2 Summary of SO_2 Four-Factor Analysis

List of Emission Control Technology	Factor #1 Cost of Compliance			Factor #2 Time Necessary for Compliance	Factor #3 Energy and Non Air Quality Environmental Impacts of Compliance	Factor #4 Remaining Useful Life of the Source	Does this Analysis Support the Installation of this Emission Control Measure?
	Installed Capital Cost ($)	Annualized Operating Cost ($/year)	Pollution Control Cost ($/ton)				
DSI/Baghouse	$34,463,571 for Power Boiler 1 $37,737,598 for Power Boiler 2	$6,144,640 for Power Boiler 1 $6,943,044 for Power Boiler 2	NA – See Section 3.2	5 years after SIP promulgation. See Section 6.3.	Energy Increased energy use to accommodate new baghouse and additional equipment for material preparation and handling. Environmental Additional solid waste generated and disposed. Loss of fly ash re-use. Increase in wastewater generation.	20 years control equipment life	No
SDA/Baghouse	$58,737,702 for Power Boiler 1 $61,962,015 for Power Boiler 2	$12,796,563 for Power Boiler 1 $13,572,909 for Power Boiler 2	NA – See Section 3.2	5 years after SIP promulgation. See Section 6.3.	Energy Increased energy use to accommodate new baghouse and additional equipment for material preparation and handling. Environmental Additional solid waste generated and disposed. Loss of fly ash re-use. Increase in wastewater generation.	20 years control equipment life	No

2 Introduction

This section discusses the pertinent regulatory background information, and a description of Northshore's Power Boilers.

2.1 Four-Factor Analysis Regulatory Background

The RHR published on July 15, 2005 by the EPA, defines regional haze as "visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources." The RHR requires state regulatory agencies to submit a series of SIPs in ten-year increments to protect visibility in certain national parks and wilderness areas, known as mandatory Federal Class I areas. The original State SIPs were due on December 17, 2007 and included milestones for establishing reasonable progress towards the visibility improvement goals, with the ultimate goal to achieve natural background visibility by 2064. The original SIP was informed by best available retrofit technology (BART) analyses that were completed on all subject-to-BART sources. The second RHR planning period requires development and submittal of updated state SIPs by July 31, 2021.

On February 24, 2020, the MPCA sent an RFI to Northshore. The RFI stated that data from the Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring sites at Boundary Waters Canoe Area (BWCA) and Voyageurs National Park (Voyageurs) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of SO_2 and NO_X. In addition, emissions from sources in Minnesota could potentially impact Class I areas in nearby states, namely Isle Royale National Park (Isle Royale) in Michigan. Although Michigan is responsible for evaluating haze in Isle Royale, Michigan must consult with surrounding states, including Minnesota, on potential cross-state haze pollution impacts. As part of the planning process for the SIP development, MPCA is working with the LADCO to evaluate regional emission reductions.

The RFIs also stated that Northshore was identified as a significant source of NO_X and SO_2 that is located close enough to the BWCA and Voyageurs to potentially cause or contribute to visibility impairment. Therefore, the MPCA requested that Northshore submit a "Four-Factors Analysis" (herein termed as a Four-Factor Analysis) by July 31, 2020 for the emission units identified in Table 2-1 as part of the State's regional haze reasonable progress.

Table 2-1 Identified Emission Units

Unit	Unit ID	Applicable Pollutants
Indurating Furnace 11	EQUI 126 & 127 (EU 100 & 104)	NO_x and SO_2
Indurating Furnace 12	EQUI 128 & 129 (EU 110 & 114)	NO_x and SO_2
Power Boiler 1	EQUI 14 (EU 001)	NO_x and SO_2
Power Boiler 2	EQUI 15 (EU 002)	NO_x and SO_2

The analysis considers potential emissions control measures by addressing the four statutory factors which are laid out in 40 CFR 51.308(f)(2)(i) and explained in the 2019 RH SIP Guidance:

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

The RFI letter to the Northshore specified that the "… analysis should be prepared using the U.S. Environmental Protection Agency guidance" referring to the final 2019 RH SIP Guidance.[3]

This report describes the background and analysis for conducting a Four-Factor Analysis for NO_X and SO_2 as applied to the review of emissions controls at Northshore for the Power Boilers identified in Table 2-1. Northshore has requested that the MPCA exclude the Indurating Furnaces identified in Table 2-1 from the sources required to conduct a Four-Factor Analysis because the furnaces are already effectively controlled with BART emission limits for NOx and SO_2. The request was submitted separately from this report on July 6, 2020. MPCA requested additional supplementary information on July 28, 2020 and Northshore responded on July 30, 2020. Copies of the two submittals are provided in Appendix C.

2.2 Source Description

Northshore mines iron ore (magnetite) and produces taconite pellets that are shipped to steel producers for processing in blast furnaces. The iron ore is crushed and routed through several concentration stages including grinding, magnetic separation, and thickening. The concentrated iron ore slurry is then dewatered, followed by mixing the filter cake with bentonite and/or other binding agents. The mixed filter cake is then formed into greenballs, which are fed through the indurating furnace(s) to create a final product.

Silver Bay Power Company, located at Northshore, has two industrial boilers listed in the RFI, identified as Power Boiler 1 and Power Boiler 2. The boilers provide process steam and electricity to the taconite operations. Each industrial boiler has an electric generator set. The electricity generated is used primarily by the Silver Bay taconite processing facility. However, a portion may be sold to the electric grid. Process steam can be produced at the power plant using evaporators that extract heat from the Power Boilers or from a recently constructed steam plant. The process steam is used in taconite processing operations.

Power Boiler 1 is a natural gas, distillate fuel oil, or coal-fired boiler, which has a dry bottom, front-wall-fired configuration and a rating of 517 MMBtu/hr, or an output of 45 megawatts. Power Boiler 2 is a natural gas or coal-fired boiler, which has a dry bottom, front-walled-fired configuration and a rating of 765 MMBtu/hr, or an output of 70 megawatts.

As of October 2019, Power Boilers 1 and 2 have been economically idled. In 2016, Northshore entered into a binding Power Service Agreement (PSA) with Minnesota Power to provide electricity to Northshore

Mining through 2031. Silver Bay Power Company is maintaining the boilers in a manner that allows startup if and when called upon by Minnesota Power to provide emergency stability to the regional electrical grid in the event of catastrophic failure. The idled boilers may resume operation in the future after termination of the PSA, but a typical operating scenario has not yet been determined. Northshore may reevaluate the control costs in the future if an operating scenario beyond the PSA is established.

3 Existing Controls and Baseline Emission Performance

This section describes the existing NO_X and SO_2 emissions controls on Northshore's Power Boilers and the baseline emissions to evaluate the costs for the associated emission control measures.

3.1 Existing Emission Controls

The existing pollution control equipment includes a fabric filter baghouse to control particulate matter on each boiler and low NO_x burners in conjunction with overfire air on Power Boiler 1 for NO_x control. SO_2 emissions from the boilers are reduced by coal processing prior to combustion. There are no post-combustion SO_2 controls. SO_2 emissions are limited by Northshore's Title V Operating Permit (TVOP) (Permit No. 07500003-010) to 1.5 lb/MMBtu on an annual basis when burning coal.

In the MPCA's 2012 SIP supplement, the MPCA revised the BART strategy for electric generating units to use the Cross-State Air Pollution Rule (CSAPR) instead of site-specific determinations. This strategy was subsequently approved by the USEPA and serves as BART for both Power Boiler 1 and 2. Subsequently, on August 21, 2012 the United States Court of Appeals for the D.C. Circuit issued its ruling to vacate CSAPR. On April 29, 2014, the U.S. Supreme Court reversed the D.C. Circuit opinion vacating CSAPR. However, the rule remained stayed at that point in time. On June 26, 2014 the U.S. government filed a motion with the U.S. Court of Appeals for the D.C. circuit to lift the stay of the CSAPR which was subsequently granted on October 23, 2014. The motion also included extending the original compliance deadlines by three years, so that Phase 1 emissions budgets apply in 2015 and 2016 (instead of 2012 and 2013), and the Phase 2 emissions budgets apply in 2017 and beyond (instead of 2014 and beyond). As noted, MPCA determined that BART-eligible sources complying with CSAPR is considered meeting BART control requirements. Both Power Boilers 1 and 2 are subject to CSAPR.

3.2 Baseline Emissions Performance

The Four-Factor Analysis requires the establishment of a baseline scenario for evaluating a potential emission control measure. EPA's August 20, 2019 memo, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" (2019 RH SIP Guidance)[4], provides recommended practices for states to consider when developing an approvable regional haze SIP for the second implementation period, which covers 2018-2028.

The 2019 RH SIP Guidance specifically addresses in Section II.B.3.b recommendations for states to consider when selecting sources for the purpose of evaluating air quality model-based visibility impacts based on a facility's level of estimated emissions in 2028. EPA also describes in Section II.B.4.b

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[4] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003. https://www.epa.gov/visibility/guidance-regional-haze-state-implementation-plans-second-implementation-period

recommendations for states to consider when estimating 2028 emissions for the purpose of evaluating potential emission control measures by referring to the same information as described in Section II.B.3.b. EPA states in Section II.B.4.b, "This information on emission reductions feeds into the estimation of visibility benefits and into calculations of cost effectiveness." The following excerpt from Section II.B.3.b describes how to estimate future emissions for evaluating both visibility impacts and potential control cost (emphasis added).

> *Selection of emissions information when estimating visibility impacts (or surrogates) for source selection purposes*
>
> *… Generally,* ***we recommend that states use estimates of 2028 emissions*** *(resolved by day and hour, as appropriate) to estimate visibility impacts (or related surrogates) when selecting sources, rather than values of recent year emissions. By doing so,* ***sources that are projected on a reasonable basis to cease or greatly reduce their operations or to install much more effective emissions controls by 2028 may be removed from further consideration early in the SIP development process****, which can reduce analytical costs.* ***Generally, the estimate of a source's 2028 emissions is based at least in part on information on the source's operation and emissions in a representative historical period. However, there may be circumstances under which it is reasonable to project that 2028 operations will differ significantly from historical emissions.*** *Enforceable requirements are one reasonable basis for projecting a change in operating parameters and thus emissions; energy efficiency, renewable energy,* ***or other such programs where there is a documented commitment to participate and a verifiable basis for quantifying any change in future emissions due to operational changes may be another****. A state considering using assumptions about future operating parameters that are significantly different than historical operating parameters should consult with its EPA Regional office.*
>
> *If a state uses a value for emissions in an earlier year, we recommend the state consider whether emissions have appreciably changed (or will change) between the earlier year, the current period, and the projected future year (2028). It is especially important to consider whether source emissions have increased or are likely to increase in the future compared to earlier emissions values.*
>
> *Use of actual emissions versus allowable emissions*
>
> ***Generally, we recommend that a reasonably projected actual level of source operation in 2028 be used to estimate 2028 actual emissions for purposes of selecting sources for control measure analysis.*** *Source operation during a historical period can inform this projection, but temporary factors that suppressed or bolstered the level of operation in the historical period should be considered,* ***along with factors that indicate a likely increase or decrease in operation.*** *See the SIP Emissions Inventory Guidance for more details. Questions about projecting 2028 emissions may be directed to EPA Regional offices.*

As reported in a news release from Cleveland-Cliffs on May 24, 2016,[5] Cleveland-Cliffs entered into a binding, multi-year Power Service Agreement (PSA) with Minnesota Power to provide electricity to Northshore through 2031. Minnesota Power's SEC 10-K filing 2016[6] also described the PSA as partially supplying electricity for Northshore from 2016-2019 while it was transitioning away from self-generation, and on December 31, 2019, Minnesota Power would supply the entire energy requirements of the facility.

Silver Bay Power Boiler 1 has not operated since June 2019 and Silver Bay Power Boiler 2 has not operated since September 2019. The following chart illustrates the reduced level of emissions through third quarter 2019 and no emissions since then. While Silver Bay Power remains fully permitted and maintained in a state of operational readiness, Silver Bay Power is not expected to operate until at least the expiration of the PSA in 2031. Accordingly, Northshore is projecting no emissions through the Regional Haze Second Planning Period (2028).

Table 3-1 Silver Bay Power Emissions

Silver Bay Power Emissions					
		Power Boiler 1		Power Boiler 2	
		SO_2 (tons)	NOx (tons)	SO_2 (tons)	NOx (tons)
January	**2019**	91	55.4	0	0
February		91.7	55.9	0	0
March		91.7	55.6	0	0
April		79.2	49.9	0	0
May		88.3	50.7	0	0
June		14.8	9.5	50.3	75.1
July		0	0	80.4	134.5
August		0	0	77	135.5
September		0	0	32.8	59.1
October		0	0	0	0
November		0	0	0	0
December		0	0	0	0
January	**2020**	0	0	0	0
February		0	0	0	0

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[5] Cliffs Natural Resources, Inc. (2016, May 24) *Cliffs Announces Agreements with Minnesota Power* [Press Release]. Retrieved from http://www.clevelandcliffs.com/English/news-center/news-releases/news-releases-details/2016/Cliffs-Announces-Agreements-with-Minnesota-Power/default.aspx

[6] Allete, Inc. (2016) *Form 10-K*. Retrieved from https://www.allete.com/Content/Documents/Investors/AnnualReports/FINALREPORTALLETE2016.pdf

Silver Bay Power Emissions				
	Power Boiler 1		Power Boiler 2	
	SO_2 (tons)	NOx (tons)	SO_2 (tons)	NOx (tons)
March	0	0	0	0
April	0	0	0	0
May	0	0	0	0
June	0	0	0	0
July	0	0	0	0

Northshore is complying with MPCA's request to conduct a Four-Factor Analysis on potential control technologies for Power Boilers 1 and 2. While Northshore has made an earnest effort to complete all other sections of the analysis, including estimating expected capital costs and annual operating costs for candidate technologies, it cannot reasonably provide a cost-effectiveness estimate in terms of dollars per ton of pollutant removed because expectations are no emissions through 2028, and therefore, no pollutants removed by installation of any control technology.

Also, for the purposes of estimating actual 2028 emissions to evaluate Class I visibility impacts, MPCA should allocate zero tons per year of NOx and SO_2 emissions to Silver Bay Power in its visibility model.

4 Four-Factor Analysis Overview

This section summarizes the Four-Factor Analysis approach with respect to the Regional Haze program detailed in the 2019 RH SIP guidance.

4.1 Emission Control Options

Prior to completing a Four-Factor Analysis of each emissions control measure, all technically feasible emission control options for Power Boilers must first be identified. Potentially available emission control measures include both physical and operational changes. Once all technically feasible emission control measures are identified, the facility justifies which emission control measures are reasonable to consider against the four factors, recognizing there is no statutory or regulatory requirement to consider all technically feasible measures.

In order to be considered technically feasible, an emissions control must have been previously installed and operated successfully on a similar source under similar physical and operating conditions. Novel controls that have not been demonstrated on full-scale, industrial operations are not considered as part of this analysis. Instead, this evaluation focuses on commercially demonstrated control options.

The control efficiencies of currently available emission control measures under consideration ranges from 25 percent to 80 percent for NO_X and 50 percent to 90 percent for SO_2. For purposes of this analysis, Northshore evaluated only those control measures that have the potential to achieve an overall pollutant reduction greater than the performance of the existing systems, including optimizations.

An evaluation of the technically feasible control measures for NO_X and SO_2 is discussed in Sections 5.1 and 6.1, respectively.

4.2 Factor #1 – Cost of Compliance

Factor #1 considers and estimates, as needed, the capital and annual operating and maintenance (O&M) costs of the control measure. As directed by the 2019 RH SIP Guidance at page 21, costs of emissions controls follow the accounting principles and generic factors from the EPA Air Pollution Control Cost Manual (EPA Control Cost Manual) [7] unless more refined site-specific estimate are available. Under this step, the annualized cost of installation and operation on a dollar per ton of pollutant removed ($/ton) of

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[7] US EPA, "EPA Air Pollution Control Cost Manual, Sixth Edition," January 2002, EPA/452/B-02-001. The EPA has updated certain sections and chapters of the manual since January 2002. These individual sections and chapters may be accessed at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution as of the date of this report.

the control measure, referred to as "average cost effectiveness," is compared to a cost effectiveness threshold that is estimated by EPA (see discussion below for the associated NO_x and SO_2 thresholds).

Generally, if the average cost effectiveness is greater than the threshold, the cost is considered to not be reasonable, pending an evaluation of other factors. Conversely, if the average cost effectiveness is less than the threshold, then the cost is considered reasonable for purposes of Factor #1, pending an evaluation of whether the absolute cost of control (i.e., costs in absolute dollars, not normalized to $/ton) is unreasonable. This situation is particularly applicable to a source with existing emissions controls with an intermediate or high degree of effectiveness.

The cost of an emissions control measure is derived using capital and annual O&M costs. Capital costs generally refer to the money required to design and build the system. This includes direct costs, such as equipment purchases, and installation costs. Indirect costs, such as engineering and construction field expenses are considered as part of the capital calculation. Annual O&M costs include labor, supplies, utilities, etc., as used to determine the annualized cost in the numerator of the cost effectiveness value.

Space limitations are also a concern for installation of new equipment. The Power Boilers are bounded by the switchyard on the north, the pelletizing plant on the west, traveling screens for the non-contact cooling water, and the lake on the south, and a steep embankment and roadway that provides access to the lower levels on the east. Additional buildings for new control equipment would require significant structural building modifications. Due to space considerations, a 60 percent markup of the total capital investment (i.e. 1.6 retrofit factor) was included in the costs to account for the retrofit installation to provide for additional site-work and construction costs to accommodate the new equipment within the facility. The site-specific estimate was based on Barr's experience with similar projects.

The denominator of the cost-effectiveness value (tons of pollutant removed) is derived as the difference in: 1) projected emissions using the current emissions control measures (2028 baseline emissions) in tons per year (tpy), and 2) expected annual emissions performance through installation of the additional control measure (controlled emissions), also in tpy. As described in Section 3.2, the cost-effectiveness calculations are not applicable because the projected emissions for 2028 are zero, and accordingly there are no expected additional reductions from any of the potential control technologies.

4.3 Factor #2 – Time Necessary for Compliance

Factor #2 considers the time needed for Northshore to comply with potential emission control measures. This includes the planning, permitting, installation, and commissioning of the selected control based on experiences with similar sources and source-specific factors.

For purposes of this analysis, and if a given NO_X or SO_2 control measure requires a unit outage as part of its installation, Northshore considers the forecasted outage schedule for the associated units in conjunction with the expected timeframe for engineering and equipment procurement following MPCA and EPA approval of the given control measure.

4.4 Factor #3 – Energy and Non-Air Quality Environmental Impacts of Compliance

Factor #3 considers the energy and non-air environmental impacts of each control measure. Energy impacts to be considered are the direct energy consumed at the source, in terms of kilowatt-hours or mass of fuels used. Non-air quality impacts may include solid or hazardous waste generation, wastewater discharges from a control device, increased water consumption, and land use. The analysis is conducted based on consideration of site-specific circumstances.

4.5 Factor #4 – Remaining Useful Life of the Source

Factor #4 considers the remaining useful life of the source, which is the difference between the date that additional emissions controls will be put in place and the date that the Northshore permanently ceases operation. Generally, the remaining useful life of the source is assumed to be longer than the useful life of the emissions control measure unless the source is under an enforceable requirement to cease operation. In the presence of an enforceable end date, the cost calculation can use a shorter period to amortize the capital cost.

For the purpose of this evaluation, the remaining useful life for the units are assumed to be longer than the useful life of the additional emission controls measures. Therefore, the expected useful life of the control measure is used to calculate the emissions reductions, amortized costs, and the resulting cost per ton removed.

5 NO_X Four-Factor Analysis for Power Boilers

This section identifies and describes various NO_X emission control measures, evaluates the four statutory factors for the Power Boilers, considers other factors, and determines if an emission control measure or measures are necessary to make reasonable progress. Consistent with EPA's guidance and MPCA direction, Northshore has completed a Four-Factor Analysis for NO_X as described in Sections 5.1 to 5.6.

5.1 NO_X Control Measures Overview

Three mechanisms by which NO_X production typically forms are thermal, fuel and prompt NO_X formation. In the case of natural gas combustion, the primary mechanism of NO_X production is through thermal NO_X formation. This mechanism arises from the thermal dissociation of nitrogen and oxygen molecules in combustion air to nitric oxide (NO). The thermal oxidation reaction is as follows:

$$N_2 + O_2 \rightarrow 2NO \qquad (1)$$

Downstream of the flame, significant amounts of NO_2 can be formed when NO is mixed with air. The reaction is as follows:

$$2NO + O_2 \rightarrow 2NO_2 \qquad (2)$$

Thermal oxidation is a function of the residence time, free oxygen, and peak reaction temperature.

Prompt NO_X is a form of thermal NO_X, which is generated at the flame boundary. It is the result of reactions between nitrogen and hydrocarbon radicals generated during combustion. Only minor amounts of NO_X are emitted as prompt NO_X.

Fuel-bound NO_X is primarily a concern with solid and liquid fuel combustion sources; it is formed as nitrogen compounds in the fuel are oxidized in the combustion process. Natural gas has minimal fuel bound nitrogen, which eliminates fuel bound NO_X as a major concern.

The following describes pertinent technical information regarding the technologies and whether the technologies are technically feasible as applied to the Power Boilers.

5.1.1 Low NOx Burners (LNB)

The LNB technology utilizes advanced-burner design to reduce NOx formation through the restriction of oxygen, flame temperature, and/or residence time. The LNB technology is a staged combustion process that is designed to split fuel combustion into two zones. In the primary zone, NOx formation is limited by either one of two methods. Under staged air-rich (high-fuel) condition, low oxygen levels limit flame temperatures resulting in less NOx formation. The primary zone is then followed by a secondary zone in which the incomplete combustion products formed in the primary zone act as reducing agents. Alternatively, under staged fuel-lean (low-fuel) conditions, excess air will reduce flame temperature to reduce NOx formation. In the secondary zone, combustion products formed in the primary zone act to lower the local oxygen concentration, resulting in a decrease in NOx formation.

The LNB control technology were installed on Power Boiler 1 in 2015. Northshore has not installed LNB control technology on Power Boiler 2.

Alone or in combination with additional controls, the LNB technology is a technically feasible option to further reduce emissions from Power Boiler 2. Based on the currently achieved emission rates a reduction in the range of 15 to 30 percent would be expected depending on operational conditions. The value of 15 percent is chosen until real data is available after installation and true performance can be assessed.

5.1.2 Overfire Air (OFA)

The OFA diverts a portion of the total combustion air from the burners and injects it through separate airports above the top level of burners. The OFA technology is the typical control technology used in coal-fired boilers and is primarily geared to reduce thermal NOx. Staging of the combustion air creates an initial fuel-rich combustion zone for a cooler fuel-rich combustion zone. This reduces the production of thermal NOx by lowering combustion temperature and limiting the availability of oxygen in the combustion zone where NOx is most likely to be formed. The OFA technology would not gain NOx control with the existing burners because the existing burners lack sufficient fuel and airflow control. However, the OFA technology is considered a technically feasible option when utilized in conjunction with new burners that would be LNB.

The OFA with LNB technologies were installed on Power Boiler 1 in 2015. Northshore has not installed OFA with LNB technologies on Power Boiler 2. Therefore, OFA with LNB technologies will be considered as a technically feasible option for Power Boiler 2. OFA used in conjunction with LNB could have a control efficiency of 30 to 50 percent. The value of 40 percent is chosen for Power Boiler 2. This value is consistent with the control efficiency achieved on Power Boiler 1. Because Northshore has previously evaluated the installation of OFA with LNB, and OFA with LNB achieves a higher control efficiency than LNB alone, Northshore has only included OFA with LNB, not LNB alone, as part of the reasonable set of controls for Power Boiler 2.

5.1.3 Selective Non-Catalytic Reduction (SNCR)

In the SNCR process, urea or ammonia-based chemicals are injected into the flue gas stream to convert nitrous oxide (NO) to molecular nitrogen, N_2, and water. The SNCR control efficiency is typically 25 percent to 50 percent. Without a catalyst, the reaction requires a high temperature range to obtain activation energy. The relevant reactions are as follows:

$NO + NH_3 + \frac{1}{4}O_2 \rightarrow N_2 + 3/2H_2O$ (1)

$NH_3 + \frac{1}{4}O_2 \rightarrow NO + 3/2H_2O$ (2)

At temperature ranges of 1470°F to 1830°F, reaction (1) dominates. At temperatures above 2000°F, reaction (2) will dominate. The temperature of flue gas at the point of reagent injection and the available residence time within the optimum reaction temperature window along with mixing efficiency are the key ingredients in achieving maximum NOx reductions with the SNCR process. The SNCR process can be retrofitted to most if not all utility boilers; however, the NOx reductions achieved are very site specific since they are highly dependent on the temperature and residence time profiles of the individual boiler. If consideration of this technology were to advance, it may be appropriate to further study and establish the residence times of the flue gases in the reaction temperature window, the location of the temperature window, ease of access for installation of the reagent injection ports at that temperature window, and the ability to achieve rapid and complete mixing of the reagent within that temperature window.

The boiler geometry and operating conditions may not provide sufficient residence time within the required operating temperature range for effective implementation of SNCR. While there is uncertainty that the residence time would be adequate, the assumption is this control option will be considered technically feasible. The control efficiency for SNCR is assumed to be 25 percent in this analysis.

5.1.4 SCR

The SCR technology is also a common technology used to control NOx emissions. The SCR control technology is a process that involves post-combustion removal of NOx from flue gas with a catalytic reactor. In the SCR process, ammonia injected into the combustion unit exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. The reaction takes place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy required for the NOx decomposition reaction. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst deactivation due to aging, ammonia slip emissions, and design of the NH_3 injection system.

Reduction catalysts are composed of active metals or ceramics with a highly porous structure. For the majority of commercial catalysts (metal oxides), the operating temperatures for the SCR process range from 480°F to 800°F. Proper reactor temperature is important in order to achieve high reductions in NOx emissions. According to the EPA Air Pollution Control Cost Manual (EPA Control Cost Manual) for SCR (updated June 2019), the NOx removal efficiency is optimized when the temperature is approximately 700°F to 750°F. Based on an engineering assessment and current NOx emissions, SCR is technically feasible for Power Boilers 1 and 2 and could provide a NOx reduction of up to 80 percent.

Based on the information presented above, Northshore has identified LNB with OFA for Power Boiler 2 only, along with SNCR, and SCR for Power Boiler 1 and 2 and to be considered whether their installation is necessary to make reasonable progress based on the factors presented below. Table 5-1 lists technically feasible NO_X control measures for the Power Boilers.

Table 5-1: Additional NO_X Control Measures with Potential Application at the Power Boilers

Control Measures
Low NOx Burners with Overfired Air (LNB-OFA) for Power Boiler 2 only
Selective Non-Catalytic Reduction (SNCR)
Selective Catalytic Reduction (SCR)

5.2 Factor #1 – Cost of Compliance

Northshore has completed cost estimates for the selected NO_X emission control measures. Due to the limited time available in responding to MPCA's request, assumptions were made in the cost estimates resulting in conservatively low equipment costs. Cost estimates for LNB-OFA are based on vendor engineering estimates, scaled for inflation using the CEPCI. The EPA Control Cost Manual was used to estimate the equipment costs for SCR and SNCR. The capital cost estimates are considered by Northshore's plant and Barr's engineering staff, based on their considerable experience with projects at Northshore and their informal conversations with other companies that have completed similar types of projects at other facilities, to be conservatively low. Cost summary spreadsheets for the NO_X emission control measures are provided in Appendix A for Power Boiler 1 and Appendix B for Power Boiler 2.

As discussed in Section 4.2, cost effectiveness in terms of dollars per ton of pollutant removed cannot reasonably be estimated because expectations are no emissions in 2028, and therefore no pollutants removed by installation of any control technology.

The resulting control cost calculations are summarized in Table 5-2.

Table 5-2: NO_X Control Cost Summary, per Unit Basis

Emission Unit	Additional Emissions Control Measure	Installed Capital Cost ($MM)	Total Annualized Costs ($/yr)
Power Boiler 1	SNCR	$7,239,275	$992,019
Power Boiler 1	SCR	$40,647,490	$4,159,366
Power Boiler 2	LNB-OFA	$11,609,362	$1,725,870
Power Boiler 2	SNCR	$8,917,925	$1,435,176
Power Boiler 2	SCR	$55,724,684	$5,985,367

Sections 5.3 through 5.5 provide a summary of the remaining three factors evaluated for the NO_X emission control measures, understanding that these projects represent substantial capital investments that are not justified on an absolute cost basis.

5.3 Factor #2 – Time Necessary for Compliance

The amount of time needed for full implementation of the emission control measure or measures varies. Typically, time for compliance includes the time needed to develop and approve the new emissions limit into the SIP by state and federal action, time for MPCA to modify Northshore's Title V operating permit to allow construction to commence, then to implement the project necessary to meet the SIP limit for the emissions control measure, including capital funding, construction, tie-in to the process, commissioning, and performance testing.

A state SIP revision is needed to approve a new statistically derived emissions limit methodology, 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).

The technologies would require significant resources and time of at least three to five years to engineer, permit, and install the equipment following the SIP revision. Although Northshore obtained a permit authorizing construction of LNB-OFA for Power Boiler 2, the permit authorization has expired according to the permit condition on page A-7 of Title V Operating Permit No. 07500003-009:

> *"The Permittee is authorized to construct the following equipment: Low Nitrogen Oxide Burners with Overfire Air Systems for EU 001 and EU 002. The construction authorization expires if construction does not commence within 18 months after receipt of such approval by Air Emissions Permit No. 07500003-009, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time."*

Power Boiler 2 is currently economically idled and construction of the LNB-OFA system has not been completed. Northshore would need to apply for a major permit amendment to install any of the control technologies in this analysis.

5.4 Factor #3 – Energy and Non-Air Quality Environmental Impacts of Compliance

The energy and non-air environmental impacts associated with implementation of the above-identified NO_X control measures are summarized herein. Northshore has considered air quality impacts for regional haze pollutants because they are directly applicable to the goals of this analysis. Overall, there are secondary air quality impacts associated with SNCR or SCR operation, which diminish some of the benefits of the NO_x reductions.

5.4.1 LNB with OFA

Negative non-air environmental impacts from the installation of LNB with OFA are summarized below:

LNB have the potential for increased steam tube damage and maintenance due to flame impingement on tubes. Flame impingement can result in premature coking of tubes, shortened run lengths, and tube failures. Increased maintenance will be required due to scale build-up and corrosion.

LNB-OFA will increase carbon monoxide emissions and will likely have PSD permitting implications.

5.4.2 SNCR

The operation of an SNCR system has significant negative environmental impacts. The impacts from the use of an SNCR system are summarized below.

As with all add-on controls, operation of an SNCR system results in an increase in energy demand to operate the system, requiring increased electrical usage by the plant. The SNCR system also requires increased water usage for dilution of the reagent and increased fuel usage for vaporization of the water in the reagent solution. The cost of energy required to operate the control devices has been included in the cost analyses found in Appendices A and B.

Urea, which is decomposed in an external reactor to form ammonia, would be used in SNCR. The SNCR system consists of an injection system for an ammonia-based reagent into the boiler at a location where the temperature is in the appropriate range for the reaction of ammonia radicals with NOx. Unreacted ammonia may escape through to the exhaust gas. This is commonly called "ammonia slip." Ammonia slip from SNCR is highly variable, 5 to 50 ppm or more according to one vendor's estimates. The ammonia that is released may also react with other pollutants in the exhaust stream to create fine PM_{10} in the form of ammonium salts. Ammonia slip will also contribute to nitrogen deposition onto nearby lakes and waters of the state, which causes undesirable biological growth.

SNCR will cause the facility to begin handling a new toxic and hazardous chemical, ammonia or urea. Working with these chemicals could potentially increase the risk of injury and death to the workers and contractors on the site. The presence of this chemical would also potentially increase the risk of hazard to neighboring industrial and rural areas. Additional regulatory burdens would be imposed on the site due to these hazards.

Fly ash is currently sold as a raw material to the concrete industry. SNCR will contaminate the fly ash, will prohibit its beneficial reuse, and will consequently eliminate the income stream this material currently provides.

5.4.3 SCR

The operation of an SCR system has significant energy requirements and negative environmental impacts. The impacts from the use of an SCR system are summarized below.

As with all add-on controls, operation of an SCR system results in an increase in energy demand due to the pressure drop across the SCR catalyst. At a minimum, this would require increased electrical usage by the plant. The cost of energy required to operate the control devices has been included in the cost analyses found in Appendices A and B.

Urea, which is decomposed in an external reactor to form ammonia, would be used in the SCR. The SCR system consists of an ammonia injection system and a catalytic reactor. Unreacted ammonia may escape through to the exhaust gas. This is commonly called "ammonia slip." Ammonia slip was estimated using 2 ppm to minimize collateral emissions of pollutants that impact visibility. The ammonia that is released may also react with other pollutants in the exhaust stream to create fine PM_{10} in the form of ammonium salts. Ammonia slip will also contribute to nitrogen deposition onto nearby lakes and waters of the state, which causes undesirable biological growth.

The SCR catalysts must also be replaced on a routine basis. In some cases, these catalysts may be classified as hazardous waste. This typically requires either returning the material to the manufacturer for recycle and reuse or disposal in permitted landfills.

Some of the issues confronted by utility boilers with SCR systems on units firing sulfur-bearing fuels involve secondary impacts from the SCR system. The impacts include the formation of SO_3 in the reactor, the emissions of unreacted ammonia from the reactor, and formation of byproducts from the reaction. These effects are often interconnected because SO_3 and unreacted ammonia can react within and downstream of the SCR reactor. The same catalyst that promotes the reactions between ammonia and NOx also promotes the oxidation of SO_2 to SO_3. It is important to understand that SO_2 oxidation is dependent on other SCR design parameters. When high levels of catalyst activity are needed to target high NOx reduction efficiencies and low levels of ammonia slip or to counteract significant catalyst deactivation rates, SO_2 oxidation rates would be expected to increase. If lower levels of SO_2 oxidation are targeted, NOx reduction, ammonia slip, or both must be compromised.

There are several reasons why industries are concerned about the level of SO_2 oxidation in an SCR reactor. In the absence of other interactions, downstream equipment (e.g., the baghouses) that operate below the sulfuric acid dew point can experience severe corrosion. In addition, sulfuric acid mist formed in such equipment can promote the formation of a visible plume. Sulfuric acid can lead to reduced control efficiency, equipment corrosion, and visible emissions. Concentrations of SO_3 and H_2SO_4 of 6 to 10 ppm can cause a visible plume, or a blue plume. To meet visible emission limitations, a wet scrubber is essential to control corrosion and to minimize the possibility of a visible plume due to formation of sulfuric acid mist. In addition, elemental mercury will oxidize forming oxidized mercury. As will be discussed under mercury oxidation section below, a wet scrubber would be required to control the oxidized mercury formed in the SCR.

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

Installation of an SCR system will cause the facility to begin handling a new toxic and hazardous chemical, ammonia or urea. Working with these chemicals could potentially increase the risk of injury and death to the workers and contractors on the site. The presence of this chemical would also potentially increase the risk of hazard to neighboring industrial and rural areas. Additional regulatory burdens would be imposed on the site due to these hazards.

Fly ash is currently sold as a raw material to the concrete industry. SCR will contaminate the fly ash, will prohibit its beneficial reuse, and will consequently eliminate the income stream this material currently provides.

5.5 Factor #4 – Remaining Useful Life of the Source

Because Northshore is assumed to continue operations for the foreseeable future, the useful life of the individual control measures (assumed 20-year life, per Section 4.5) is used to calculate emission reductions and amortized costs.

5.6 NO_X Four-Factor Analysis Conclusion

Based on the analysis conducted in Sections 5.1 through 5.5, Northshore has determined that installation of additional NO_X emissions measures at the Power Boilers 1 and 2 beyond those described in Section 3.1 are not required to make reasonable progress in reducing NO_X emissions. As such, Northshore intends to continue complying with CSAPR, which EPA has been determined to be better than BART.

6 SO_2 Four-Factor Analysis for Power Boilers

This section identifies and describes various SO_2 emission control measures, evaluates the four statutory factors for Power Boilers 1 and 2, considers other factors, and determines if an emission control measure or measures are necessary to make reasonable progress. Consistent with EPA's guidance and MPCA direction, Northshore has completed a Four-Factor Analysis for SO_2 as described in Sections 6.1 to 6.6.

6.1 SO_2 Control Measures Overview

SO_2 emissions from the Power Boilers occur as a result of oxidation of sulfur in the fuels combusted. The following describes pertinent technical information regarding the control measure and whether the control measure is technically feasible as applied to Power Boilers 1 and 2.

6.1.1 Dry Sorbent Injection (DSI) with New Baghouse

DSI involves the injection of a lime, limestone powder, or trona into the exhaust gas stream. The stream is then passed through a baghouse or electrostatic precipitator to remove the sorbent and entrained SO_2. The process was developed as a lower cost flue gas desulfurization option because the mixing occurs directly in the exhaust gas stream instead of in a separate tower. Depending on the residence time and gas stream temperature, sorbent injection control efficiency is typically between 50 percent and 70 percent. For Power Boiler 1 and 2, the existing baghouse could not handle the additional particulate loading without a corresponding increase in particulate emissions. Therefore, it is technically feasible, but is not viable as a retrofit with the existing baghouse due to an increase in PM loading. If the DSI is accompanied with a new baghouse, removal is expected to be 70 percent when using trona. DSI is technically feasible for Power Boilers 1 and 2.

6.1.2 Spray Dryer Absorber (SDA) with New Baghouse

SDA systems spray lime slurry into an absorption tower where SO_2 is absorbed by the slurry, forming $CaSO_3/CaSO_4$. The liquid-to-gas ratio is such that the water evaporates before the droplets reach the bottom of the tower. The dry solids are carried out with the gas and collected with a fabric filter. The normal SO_2 control efficiency range for SDA is up to 90 percent, and 90 percent was used in this analysis.

Based on the information contained with this report, SDA is considered an available technology for SO_2 reduction for this Four-Factor Analysis. For Power Boiler 1 and 2, the existing baghouse could not handle the additional particulate loading without a corresponding increase in particulate emissions. Therefore, it is technically feasible, but is not viable as a retrofit with the existing baghouse due to an increase in PM loading. If the SDA system is accompanied with a new baghouse, it is technically feasible for Power Boilers 1 and 2.

Based on the information presented above, Northshore has identified DSI and SDA technologies, each accompanied by new baghouses, to be considered whether their installation is necessary to make reasonable progress reducing SO_2 emissions based on the factors presented below. Table 6-1 lists technically feasible SO_2 control measures for Power Boilers 1 and 2.

Table 6-1 Additional SO_2 Control Measures with Potential Application at Power Boilers

Control Measures
Dry Sorbent Injection (DSI) with New Baghouse
Spray Dryer Absorption (SDA) with New Baghouse

6.2 Factor #1 – Cost of Compliance

Northshore has completed costs estimate for the selected SO_2 emission control measures. Due to the limited time available in responding to MPCA’s request, assumptions were made in the cost estimates resulting in conservatively low equipment costs. Cost estimates are based on vendor engineering estimates for installation of equipment at similar projects, scaled for Northshore’s design flow and adjusted for inflation using the CEPCI.

The capital cost estimates are considered by Northshore’s plant and Barr’s engineering staff, based on their considerable experience with projects at Northshore and their informal conversations with other companies that have completed similar types of projects at other facilities, to be conservatively low. Cost summary spreadsheets for the SO_2 emission control measures are provided in Appendix A for Power Boiler 1 and Appendix B for Power Boiler 2.

As discussed in Section 4.2, cost effectiveness in terms of dollars per ton of pollutant removed cannot reasonably be estimated because there are expected to be no emissions in 2028, and therefore no pollutants removed by installation of any control technology.

The resulting control cost calculations are summarized in Table 6-2.

Table 6-2: SO_2 Control Cost Summary for Power Boilers 1 and 2, per Unit Basis

Emission Unit	Additional Emissions Control Measure	Installed Capital Cost ($MM)	Total Annualized Costs ($/yr)
Power Boiler 1	DSI/Baghouse	$34,463,571	$6,144,640
Power Boiler 1	SDA/Baghouse	$58,737,702	$12,796,563
Power Boiler 2	DSI/Baghouse	$37,737,598	$6,943,044
Power Boiler 2	SDA/Baghouse	$61,962,015	$13,572,909

Sections 6.3 through 6.5 provide a summary of the remaining three factors evaluated for the SO_2 emission control measures, understanding that these projects represent substantial capital investments that are not justified on a cost per ton or absolute cost basis.

6.3 Factor #2 – Time Necessary for Compliance

Typically, time for compliance includes the time needed to develop and approve the new emissions limit into the SIP by state and federal action, time for MPCA to modify Northshore's Title V operating permit to allow construction to commence, then to implement the project necessary to meet the SIP limit for the emissions control measure, including capital funding, construction, tie-in to the process, commissioning, and performance testing.

A SIP revision is needed to approve a new statistically derived emissions limit methodology, e.g. 99 percent UPL. Barr assumes that the revisions would occur in 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 control measures would require significant resources and time of at least three to five years to engineer, permit, and install the equipment.

6.4 Factor #3 – Energy and Non-Air Quality Environmental Impacts of Compliance

The energy and non-air environmental impacts associated with implementation of the above identified SO_2 control measures are summarized herein.

6.4.1 Energy Impacts

For DSI or SDA, the electricity requirements are expected to increase with the new baghouse. Similar to the NOx add-on controls, operation of add-on SO_2 control systems such as SDA with baghouses results in increased energy use due to the pressure drop across the reactor and fabric filter, material preparation such as grinding limestone, additional material-handling equipment such as pumps and blowers, and steam requirements. Power consumption is also affected by the reagent utilization of the control technology, which also affects the control efficiency of the control technology. The cost of energy required to operate the control devices has been included in the cost analyses found in Appendices A and B.

6.4.2 Environmental Impacts

The SO_2 control technology would generate a significant amount of solid waste that would require disposal in permitted landfills. The collected solids would not be suitable for recycling back into the process or for beneficial reuse resale as currently occurs, resulting in increased solids to the landfill. In addition, the SO_2 control technology processes would generate additional wastewater that would require modifications to their existing wastewater permits for inclusion of this additional wastewater.

6.5 Factor #4 – Remaining Useful Life of the Source

Because Northshore is assumed to continue operations for the foreseeable future, the useful life of the individual control measures (assumed 20-year life, per Section 4.5) is used to calculate emission reductions and amortized costs.

6.6 SO_2 Four-Factor Analysis Conclusion

Based on the analysis conducted in Sections 6.1 through 6.5, Northshore has determined that installation of additional SO_2 emissions measures at Power Boilers 1 and 2 beyond those described in Section 3.1 are not required to make reasonable progress in reducing SO_2 emissions. As such, Northshore proposes to maintain compliance with its SO_2 emission limits of 1.5 lb/MMBtu in its Title V Operating Permit and to continue complying with CSAPR, which EPA has determined to be better than BART.

Appendix A

Unit-specific Screening Level Cost Summary for Power Boiler 1

Cleveland Cliffs - Northshore Mining Power Boiler #1
Appendix A - Four-Factor Control Cost Analysis
Table A-1: Cost Summary

NO_x Control Cost Summary

Control Technology	Control Eff %	Installed Capital Cost $	Annualized Operating Cost $/yr
Selective Non-Catalytic Reduction (SNCR)	25%	$7,239,275	$992,019
Selective Catalytic Reduction (SCR)	80%	$40,647,490	$4,159,366

SO_2 Control Cost Summary

Control Technology	Control Eff %	Installed Capital Cost $	Annualized Operating Cost $/yr
Dry Sorbent Injection (DSI) with Baghouse	70%	$34,463,571	$6,144,640
Spray Dry Absorber (SDA) with Baghouse	90%	$58,737,702	$12,796,563

Cleveland Cliffs - Northshore Mining Power Boiler #1
Appendix A - Four-Factor Control Cost Analysis
Table A-2: Summary of Utility, Chemical and Supply Costs

Operating Unit:	Power Boiler 1	**Study Year**	2020
Emission Unit Number	EQUI 14 / EU 001		
Stack/Vent Number	SV 001		

	2020					
Item	**Unit Cost**	**Units**	**Cost**	**Year**	**Data Source**	**Notes**
Operating Labor	60	$/hr		2020	Site-specific data	
Maintenance Labor	60	$/hr		2020	Site-specific data	
Electricity	0.076	$/kwh			EIA 2020 Avg Price Industrial Nat Gas in MN	
Natural Gas	4.98	$/kscf		NA	5-year average based on 2014-2018 gas prices on epia.gov	
Water	0.34	$/mgal	0.20	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 2	Adjusted for 3% inflation
Cooling Water	0.42	$/mgal	0.23	1999	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 3.1 Chapter 1	Ch 1 Carbon Absorbers, 1999 $0.15-$0.30 Avg of 22.5 and 7 yrs and 3% inflation
Compressed Air	0.48	$/kscf	0.38	2012	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1	Adjusted for 3% inflation
Chemicals & Supplies						
Lime	167.17	$/ton	140.00	2014	Site Specific	Adjusted for 3% inflation
Trona	285.00	$/ton			Vendor estimated delivered cost	
Urea 50% Solution	1.81	$/gallon	1.66	2017	EPA Control Cost Manual Chapter 7, 7th Edition default	Adjusted for 3% inflation
Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours			EPA Control Cost Manual Chapter 7, 7th Edition default	
SCR Catalyst cost (CC $_{replace}$)	248	$/cubic foot (includes rem	227	2017	EPA Control Cost Manual Chapter 7, 7th Edition default	Adjusted for 3% inflation
Cost per bag	249.27	$/bag	160	2005	Northshore Mining March 2009 submittal to MPCA	Adjusted for 3% inflation
Other						
Sales Tax	6.875%			2020	Current MN sales tax rate	
Interest Rate	5.50%				EPA Control Cost Manual Chapter 7, 7th Edition default	
Solid Waste Disposal	42.56	$/ton	25	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1	Adjusted for 3% inflation
Contingencies	10%	of purchased equip cost (B)			EPA Control Cost Manual Chapter 2, 7th Edition estimates contingencies from 5-15%. Assumed the mid range	
Markup on capital investment (retrofit factor)	60%				CUECost Workbook Version 1.0, USEPA Document Page 2 allows up to a 60% retrofit factor for installations in existing facilities.	
Operating Information						
Annual Op. Hrs	5,650	Hours			2017 Site-specific operating hours	
Utilization Rate	73%				Site-specific estimate, 2017 emission inventory	
Design Capacity	517.0	MMBTU/hr			Site-specific estimate	
Equipment Life	20	yrs			Assumed	
Temperature	280	Deg F			Site-specific estimate	
Moisture Content	8.8%				Site-specific estimate	
Actual Flow Rate	200,800	acfm			Site-specific estimate	
Standardized Flow Rate	140,800	scfm @ 68º F	133,505	scfm @ 32º F	Site-specific estimate	
Dry Std Flow Rate	128,300	dscfm @ 68º F			Site-specific estimate	
Fuel higher heating value (HHV)	8,826	BTU/lb			EPA Control Cost Manual Chapter 7, 7th Edition default for sub-bituminous	
Plant Elevation	764	Feet above sea level			Site Elevation	
Fuel Sulfur Content (%)	0.41	%			EPA Control Cost Manual Chapter 7, 7th Edition default for sub-bituminous	
# days boiler operates	235	days			Site Specific Data	
Technology Control Efficiency						
SDA - SO_2 Control Efficiency	90%				EPA fact sheet for flue gas desulfurization (new installations) https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf	
DSI - SO_2 Control Efficiency	70%	Trona Control Efficiency			Control efficiency is based on trona as injected reagent.	
SCR - NO_x Control Efficiency	80%				Based on engineering assessment.	
SNCR - NO_x Performance	0.26	lb/MMBtu			EPA Control Cost Manual Chapter 7, 7th Edition, SCR Figure 1.1 *(efficiency vs inlet NOx concentration approximation (25%) reduction)*	

Air Pollution Control Cost Estimation Spreadsheet
For Selective Non Catalytic Reduction (SNCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards

(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Non-Catalytic Reduction (SNCR) control device. SNCR is a post-combustion control technology for reducing NOx emissions by injecting an ammonia-base reagent (urea or ammonia) into the furnace at a location where the temperature is in the appropriate range for ammonia radicals to react with NOx to form nitrogen and water.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SNCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SNCR control technology and the cost methodologies, see Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SNCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM version 6). The size and costs of the SNCR are based primarily on four parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, and the reagent consumption. This approach provides study-level estimates (±30%) of SNCR capital and annual costs. Default data in the spreadsheet is taken from the SNCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions, such as the boiler configuration and fuel type. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will reset the NSR, plant elevation, estimated equipment life, desired dollar year, cost index (to match desired dollar year), annual interest rate, unit costs for fuel, electricity, reagent, water and ash disposal, and the cost factors for maintenance cost and administrative charges. All other data entry fields will be blank.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SNCR is for new construction or retrofit of an existing boiler. 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.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you selected coal, select the type of coal burned from the drop down menu. The NOx emissions rate, weight percent coal ash and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided.

Step 4: Complete all of the cells highlighted in yellow. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.015 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SNCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SNCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.6

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 517 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 8,826 Btu/lb

*HHV value of 8826 Btu/lb is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual fuel consumption? 241,600,555

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

coal burned: Sub-Bituminous

Enter the sulfur content (%S) =

or

Select the appropriate SO_2 emission rate: Not Applicable

*The sulfur content of 0.41% is a default value. See below for data source. Enter actual value, if known.

Ash content (%Ash): percent by weight

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})		days
Inlet NO_x Emissions (NOx_{in}) to SNCR		lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR		lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)		

Plant Elevation	764	Feet above sea level

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

Concentration of reagent as stored (C_{stored})		Percent
Density of reagent as stored (ρ_{stored})		lb/ft^3
Concentration of reagent injected (C_{inj})		percent
Number of days reagent is stored ($t_{storage}$)		days
Estimated equipment life		Years
	Urea ▼	

Densities of typical SNCR reagents:

50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Enter the cost data for the proposed SNCR:

Desired dollar-year	2020			
CEPCI for 2020	607.5	2019 Final CEPCI Value	541.7	2016 CEPCI
Annual Interest Rate (i)	5.50	Percent*		
Fuel ($Cost_{fuel}$)	2.13	\$/MMBtu		
Reagent ($Cost_{reag}$)	1.81	\$/gallon for a 50 percent solution of urea		
Water ($Cost_{water}$)	0.0051	\$/gallon		
Electricity ($Cost_{elect}$)	0.0760	\$/kWh		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	42.56	\$/ton		

CEPCI = Chemical Engineering Plant Cost Index

* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/MMBtu)	1.89	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Ash Disposal Cost ($/ton)	48.8	Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft Demand. July 11, 2017. Available at: http://www.wastebusinessjournal.com/news/wbj20170711A.htm.	
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Percent ash content for Coal (% weight)	5.84	Average ash content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	517	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	513,133,923	lbs/year
Actual Annual fuel consumption (Mactual) =		241,600,555	lbs/year
Heat Rate Factor (HRF) =	NPHR/10 =	1.00	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.30	fraction
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	5650	hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	25	percent
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO_2 Emission rate =	$(\%S/100)x(64/32)*(1x10^6)/HHV$ =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.03	
Atmospheric pressure at 764 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.3	psia
Retrofit Factor (RF) =	Retrofit to existing boiler	1.60	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	118	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	236	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	24.9	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	8,400	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	8.5	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	113	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.96	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/HHV =	6.3	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$2,233,111 in 2020 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2020 dollars
Balance of Plant Costs (BOP_{cost}) =	$3,335,563 in 2020 dollars
Total Capital Investment (TCI) =	$7,239,275 in 2020 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$2,233,111 in 2020 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2020 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$3,335,563 in 2020 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$382,834	in 2020 dollars
Indirect Annual Costs (IDAC) =	$609,185	in 2020 dollars
Total annual costs (TAC) = DAC + IDAC	$992,019	in 2020 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$108,589	in 2020 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$255,054	in 2020 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$3,652	in 2020 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$3,281	in 2020 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$11,498	in 2020 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$761	in 2020 dollars
Direct Annual Cost =		$382,834	in 2020 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$3,258	in 2020 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$605,927	in 2020 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$609,185	in 2020 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$992,019	per year in 2020 dollars
NOx Removed =	N/A	tons/year
Cost Effectiveness =	N/A	per ton of NOx removed in 2020 dollars

Note: Cost Effectiveness is not determined because emissions in 2028 are projected to be zero.

Cleveland Cliffs - Northshore Mining Power Boiler #1
Appendix A - Four-Factor Control Cost Analysis
Table A-3: NO$_x$ Control - Selective Catalytic Reduction

Operating Unit: **Power Boiler 1**

Emission Unit Number	EQUI 14 / EU 001		Stack/Vent Number	SV 001	
Design Capacity	517	mmbtu/hr	Standardized Flow Rate	133,505	scfm @ 32º F
Expected Utilization Rate	73%		Temperature	280	Deg F
Expected Annual Hours of Operation	5,650	Hours	Moisture Content	8.8%	
Annual Interest Rate	5.5%		Actual Flow Rate	200,800	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	140,800	scfm @ 68º F
			Dry Std Flow Rate	128,300	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs	EPRI Correlation							
Total Capital Investment (TCI) with Retrofit								40,647,490
								40,647,490
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						**753,037**
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						**3,406,329**
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**4,159,366**

Notes & Assumptions

1 Estimated Equipment Cost per EPA Air Pollution Control Cost Manual 7th Ed SCR Control Cost Spreadsheet
2 Costs scaled to current dollars from the Chemical Engineering Plant Cost Index (CEPCI)

Cleveland Cliffs - Northshore Mining Power Boiler #1
Appendix A - Four-Factor Control Cost Analysis
Table A-3: NOx Control - Selective Catalytic Reduction

CAPITAL COSTS			
SCR Capital Costs (SCRcost)		*Refer to the SCR Cost Estimate tab*	22,537,169
Reagent Preparation Costs (RPC)		*Refer to the SCR Cost Estimate tab*	3,510,336
Air Pre-Heater Costs (APHC)		*Refer to the SCR Cost Estimate tab*	-
Balance of Plant Costs (BPC)		*Refer to the SCR Cost Estimate tab*	5,219,795
Retrofit factor	60%	*of TCI, see SCR Cost Estimate tab*	
Total Capital Investment (TCI)			**40,647,490**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Maintenance			
Annual Maintenance Cost =		*Refer to the SCR Cost Estimate tab*	203,237
Utilities, Supplies, Replacements & Waste Management			
Annual Electricity Cost =		*Refer to the SCR Cost Estimate tab*	126,956
Annual Catalyst Replacement Cost =		*Refer to the SCR Cost Estimate tab*	208,599
Annual Reagent Cost =		*Refer to the SCR Cost Estimate tab*	214,245
Total Annual Direct Operating Costs			**753,037**
Indirect Operating Costs			
Administrative Charges (AC) =		*Refer to the SCR Cost Estimate tab*	4,134
Capital Recovery Costs (CR)=	0.0837	*Refer to the SCR Cost Estimate tab*	3,402,195
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**3,406,329**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,159,366**

Cleveland Cliffs - Northshore Mining Power Boiler #1
Appendix A - Four-Factor Control Cost Analysis
Table A-3: NOx Control - Selective Catalytic Reduction

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catayst - Refer to the SCR Cost Estimate Tab

Reagent Use

Refer to the SCR Cost Estimate tab

Operating Cost Calculations		
Refer to the SCR Cost Estimate tab	**Annual hours of operation:**	**5,650**
	Utilization Rate:	**73%**

Air Pollution Control Cost Estimation Spreadsheet
For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO_x emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO_x within a specific temperature range to produce N_2 and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 6). For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retrofit of an existing boiler. 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.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.6

* NOTE: You must document why a retrofit factor of 1.6 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 517 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 8,826 Btu/lb

*HHV value of 8826 Btu/lb is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual fuel consumption? 241,600,555

Operating Hours 5,650 323,950,000.00

Enter the net plant heat input rate (NPHR) 10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 764 Feet above sea level

coal burned: Sub-Bituminous

Enter the sulfur content (%S) =

*The sulfur content of 0.41% is a default value. See below for data source. Enter actual value, if known.

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	
Bituminous	
Sub-Bituminous	
Lignite	

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

○ Method 1
● Method 2
○ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})		days
Number of days the boiler operates (t_{plant})		days
Inlet NO_x Emissions (NOx_{in}) to SCR		lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR		lb/MMBtu
Stoichiometric Ratio Factor (SRF)		

*The SRF value of 0.525 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})		
Number of catalyst layers (R_{layer})		
Number of empty catalyst layers (R_{empty})		
Ammonia Slip (Slip) provided by vendor		ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)		Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)		acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)		°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})		ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	50	percent*
Density of reagent as stored (ρ_{stored})	71	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 50% and density of 71 lbs/cft are default values for urea reagent. User should enter actual values for reagent, if different from the default values provided.

Select the reagent used: Urea ▼

Enter the cost data for the proposed SCR:

Desired dollar-year					
CEPCI for 2019		2019 CEPCI Final Value		2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)		Percent*			* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent ($Cost_{reag}$)		$/gallon for 50% urea			
Electricity ($Cost_{elect}$)		$/kWh			
Catalyst cost ($CC_{replace}$)		$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate		$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day		hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SCR Cost Development Methodology, Chapter 5, Attachment 5-3, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-3_scr_cost_development_methodology.pdf	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	517	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	513,133,923	lbs/year
Actual Annual fuel consumption (Mactual) =		241,600,555	lbs/year
Heat Rate Factor (HRF) =	NPHR/10 =	1.00	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.471	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	5,650	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent
NO_x removal factor (NRF) =	EF/80 =	1.00	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	301,336	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	144.04	/hour
Residence Time	$1/V_{space}$	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.03	
Atmospheric pressure at sea level (P) =	2116 x $[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.3	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.60	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = H$_{catalyts}$/(t$_{SCR}$ x 24 hours) rounded to the nearest integer	0.2303	Fraction
Catalyst volume (Vol$_{catalyst}$) =	2.81 x Q$_{B}$ x EF $_{adj}$ x Slipadj x NOx$_{adj}$ x S$_{adj}$ x (T$_{adj}$/N$_{scr}$)	2,091.98	Cubic feet
Cross sectional area of the catalyst (A$_{catalyst}$) =	q$_{flue\ gas}$ /(16ft/sec x 60 sec/min)	314	ft^{2}
Height of each catalyst layer (H$_{layer}$) =	(Vol$_{catalyst}$/(R$_{layer}$ x A$_{catalyst}$)) + 1 (rounded to next highest integer)	3	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A$_{SCR}$) =	1.15 x A$_{catalyst}$	361	ft^{2}
Reactor length and width dimensions for a square reactor =	(A$_{SCR}$)$^{0.5}$	19.0	feet
Reactor height =	(R$_{layer}$ + R$_{empty}$) x (7ft + h$_{layer}$) + 9ft	50	feet

Reagent Data:

Type of reagent used: Urea

Molecular Weight of Reagent (MW) = 60.06 g/mole
Density = 71 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	99	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	198	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	21	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	7,100	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(\text{CoalF x HRF})^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	295.66	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$22,537,169	in 2019 dollars
Reagent Preparation Cost (RPC) =	$3,510,336	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2019 dollars
Balance of Plant Costs (BPC) =	$5,219,795	in 2019 dollars
Total Capital Investment (TCI) =	$40,647,490	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$22,537,169 in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564,000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564,000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$3,510,336 in 2019 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529{,}000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$5,219,795 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	\$753,037 in 2019 dollars
Indirect Annual Costs (IDAC) =	\$3,406,329 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	\$4,159,366 in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	\$203,237 in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	\$214,245 in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	\$126,956 in 2019 dollars
Annual Catalyst Replacement Cost =		\$208,599 in 2019 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.		
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x $(CC_{replace}/R_{layer})$ x FWF	* Calculation Method 2 selected.
Method 2 (for coal-fired industrial boilers):	$(Q_B/NPHR)$ x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x $(CC_{replace})$ x 35.3	
Direct Annual Cost =		\$753,037 in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	\$4,134 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	\$3,402,195 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	\$3,406,329 in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$4,159,366	per year in 2019 dollars
NOx Removed =	N/A	tons/year
Cost Effectiveness =	N/A	per ton of NOx removed in 2019 dollars

Note: Cost Effectiveness is not determined because emissions in 2028 are projected to be zero.

Cleveland Cliffs - Northshore Mining Power Boiler #1
Appendix A - Four-Factor Control Cost Analysis
Table A-4: SO2 Control Dry Sorbent Injection (DSI) with Baghouse (including injection system)

Operating Unit: **Power Boiler 1**

Emission Unit Number			Stack/Vent Number		
Design Capacity	517	MMBtu/hr	Standardized Flow Rate	133,505	scfm @ 32º F
Utilization Rate	73%		Exhaust Temperature	280	Deg F
Annual Operating Hours	5,650	hr/yr	Exhaust Moisture Content	8.8%	
Annual Interest Rate	5.50%		Actual Flow Rate	200,800	acfm
Control Equipment Life	20	yrs	Standardized Flow Rate	140,800	scfm @ 68º F
Plant Elevation	764	ft	Dry Std Flow Rate	128,300	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs						
Direct Capital Costs						
Purchased Equipment (A)						**8,140,624**
Purchased Equipment Total (B)	22%	of control device cost (A)				**9,921,386**
Installation - Standard Costs	74%	of purchased equip cost (B)				7,341,825
Installation - Site Specific Costs						N/A
Installation Total						7,341,825
Total Direct Capital Cost, DC						17,263,211
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)				5,159,121
Total Capital Investment (TCI) = DC + IC						**21,539,732**
Adjusted TCI for Replacement Parts						21,539,732
Total Capital Investment (TCI) with Retrofit Factor						**34,463,571**
Operating Costs						
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.				1,566,197
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost				4,578,443
Total Annual Cost (Annualized Capital Cost + Operating Cost)						**6,144,640**

Notes & Assumptions

1 Baghouse cost estimate from 2008 vendor data for 165,000 acfm baghouse, (Northshore Mining March 2009 submittal to MPCA)
2 Purchased equipment costs include anciliary equipment
3 Costs scaled up to design airflow using the 6/10 power law
4 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
5 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1
6 Cost Effectiveness in $/ton removed is not determined because emissions in 2028 are projected to be zero.

Cleveland Cliffs - Northshore Mining Power Boiler #1
Appendix A - Four-Factor Control Cost Analysis
Table A-4: SO2 Control Dry Sorbent Injection (DSI) with Baghouse (including injection system)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**8,140,624**
Purchased Equipment Costs (A) - Injection System + auxiliary equipment, EC			
Instrumentation	10%	Included in vendor estimate	814,062
State Sales Taxes	6.9%	of control device cost (A)	559,668
Freight	5%	of control device cost (A)	407,031
Purchased Equipment Total (B)	22%		**9,921,386**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	396,855
Handling & erection	50%	of purchased equip cost (B)	4,960,693
Electrical	8%	of purchased equip cost (B)	793,711
Piping	1%	of purchased equip cost (B)	99,214
Insulation	7%	of purchased equip cost (B)	694,497
Painting	4%	Included in vendor estimate	396,855
Installation Subtotal Standard Expenses	74%		**7,341,825**
Other Specific Costs (see summary)			
Site Preparation, as required	N/A	Site Specific	
Buildings, as required	N/A	Site Specific	
Lost Production for Tie-In	N/A	Site Specific	
Total Site Specific Costs			N/A
Installation Total			**7,341,825**
Total Direct Capital Cost, DC			**17,263,211**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	992,139
Construction & field expenses	20%	of purchased equip cost (B)	1,984,277
Contractor fees	10%	of purchased equip cost (B)	992,139
Start-up	1%	of purchased equip cost (B)	99,214
Performance test	1%	of purchased equip cost (B)	99,214
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	992,139
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**5,159,121**
Total Capital Investment (TCI) = DC + IC			**22,422,332**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**21,539,732**
Total Capital Investment (TCI) with Retrofit Factor	60%		**34,463,571**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	60.00	$/Hr	84,750
Supervisor	0.15	of Op Labor	12,713
Maintenance			
Maintenance Labor	60.00	$/Hr	42,375
Maintenance Materials	100	% of Maintenance Labor	42,375
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.08	$/kwh, 218.1 kW-hr, 5650 hr/yr, 73% utilization	93,639
N/A			-
Compressed Air	0.48	$/kscf, 2.0 scfm/kacfm, 5650 hr/yr, 73% utilization	47,841
N/A			-
Solid Waste Disposal	42.56	$/ton, 0.5 ton/hr, 5650 hr/yr, 73% utilization	84,175
Trona	285.00	$/ton, 1,193.8 lb/hr, 5650 hr/yr, 73% utilization	701,646
Filter Bags	249.27	$/bag, 2,952 bags, 5650 hr/yr, 73% utilization	206,684
Lost Revenue - Fly Ash			250,000
N/A			-
N/A			-
N/A			-
Total Annual Direct Operating Costs			**1,566,197**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	109,328
Administration (2% total capital costs)	2%	of total capital costs (TCI)	689,271
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	344,636
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	344,636
Capital Recovery	0.0837	for a 20-year equipment life and a 5.5% interest rate	2,883,889
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery costs	**4,578,443**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**6,144,640**

Cleveland Cliffs - Northshore Mining Power Boiler #1
Appendix A - Four-Factor Control Cost Analysis
Table A-4: SO2 Control Dry Sorbent Injection (DSI) with Baghouse (including injection system)

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment: **Filter Bags**

Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	249.27	$/bag
Amount Required	2952	# of Bags for new baghouse
Total Rep Parts Cost	823,565	Cost adjusted for freight, sales tax, and bag disposal
Installation Labor	59,035	20 min per bag
Total Installed Cost	**882,600**	
Annualized Cost	**206,684**	

Electrical Use

	Flow acfm	D P in H2O	kWhr/yr	
Blower	200,800	6.00	1,232,089	Electricity for new baghouse
Total			1,232,089	

Reagent Use & Other Operating Costs

Trona use - 1.5 NSR	214.87	lb/hr SO2	1193.80	lb/hr Trona
Solid Waste Disposal	2,709	ton/yr DSI unreacted sorbent and reaction byproducts		

Operating Cost Calculations

Utilization Rate	73%	Annual Operating Hours	5,650

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***		**Annual Cost**	**Comments**
Operating Labor								
Op Labor	60.00	$/Hr	2.0	hr/8 hr shift	1,413	$	84,750	$/Hr, 2.0 hr/8 hr shift, 1,413 hr/yr
Supervisor	15%	of Op Labor			NA	$	12,713	% of Operator Costs
Maintenance								
Maint Labor	60.00	$/Hr	1.0	hr/8 hr shift	706	$	42,375	$/Hr, 1.0 hr/8 hr shift, 706 hr/yr
Maint Mtls	100%	of Maintenance Labor			NA	$	42,375	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management								
Electricity	0.076	$/kwh	218.1	kW-hr	1,232,089	$	93,639	$/kwh, 218.1 kW-hr, 5650 hr/yr, 73% utilization
Water			N/A	gpm				
Compressed Air	0.481	$/kscf	2.0	scfm/kacfm	99,384	$	47,841	$/kscf, 2.0 scfm/kacfm, 5650 hr/yr, 73% utilization
Cooling Water			N/A	gpm				
Solid Waste Disposal	42.56	$/ton	0.5	ton/hr	1,978	$	84,175	$/ton, 0.5 ton/hr, 5650 hr/yr, 73% utilization
Trona	285.00	$/ton	1,193.8	lb/hr	2,462	$	701,646	$/ton, 1,193.8 lb/hr, 5650 hr/yr, 73% utilization
Filter Bags	249.27	$/bag	2,952	bags	N/A	$	206,684	$/bag, 2,952 bags, 5650 hr/yr, 73% utilization

Cleveland Cliffs - Northshore Mining Power Boiler #1
Appendix A - Four-Factor Control Cost Analysis
Table A-5: SO2 Control Spray Dry Absorber (SDA) with Baghouse (including lime slaking system)

Operating Unit: **Power Boiler 1**

Emission Unit Number	EQUI 14 / EU 001		Stack/Vent Number	SV 001	
Design Capacity	517	MMBtu/hr	Standardized Flow Rate	133,505	scfm @ 32º F
Utilization Rate	73%		Temperature	280	Deg F
Annual Operating Hours	5,650	Hours	Moisture Content	8.8%	
Annual Interest Rate	5.5%		Actual Flow Rate	200,800	acfm
Equipment Life	20	yrs	Standardized Flow Rate	140,800	scfm @ 68º F
			Dry Std Flow Rate	128,300	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								**21,325,238**
Purchased Equipment Total (B)	22%	of control device cost (A)						**25,990,134**
Installation - Standard Costs	74%	of purchased equip cost (B)						19,232,699
Installation - Site Specific Costs								NA
Installation Total								19,232,699
Total Direct Capital Cost, DC								45,222,832
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)						13,514,869
Total Capital Investment (TCI) = DC + IC								**58,737,702**
Adjusted TCI for Replacment Parts								**57,855,102**
TCI with Retrofit Factor								**92,568,163**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						1,031,783
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						11,764,780
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**12,796,563**

Notes & Assumptions

1. Capital cost estimate based on flow rate of 300,000 scfm from Northshore Mining Powerhouse #2 March 2009 submittal including anciliary equipment
2. Costs scaled up to design airflow using the 6/10 power law
3. Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1
5. Cost Effectiveness in $/ton removed is not determined because emissions in 2028 are projected to be zero.

Cleveland Cliffs - Northshore Mining Power Boiler #1
Appendix A - Four-Factor Control Cost Analysis
Table A-5: SO2 Control Spray Dry Absorber (SDA) with Baghouse (including lime slaking system)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) [(1)]			**21,325,238**
Purchased Equipment Costs (A) - Absorber + packing + auxiliary equipment, EC			
Instrumentation	10%	of control device cost (A)	2,132,524
State Sales Taxes	6.9%	of control device cost (A)	1,466,110
Freight	5%	of control device cost (A)	1,066,262
Purchased Equipment Total (B)	22%		**25,990,134**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	1,039,605
Handling & erection	50%	of purchased equip cost (B)	12,995,067
Electrical	8%	of purchased equip cost (B)	2,079,211
Piping	1%	of purchased equip cost (B)	259,901
Insulation	7%	of purchased equip cost (B)	1,819,309
Painting	4%	of purchased equip cost (B)	1,039,605
Installation Subtotal Standard Expenses	74%		**19,232,699**
Other Specific Costs (see summary)			
Site Preparation, as required	N/A	Site Specific	-
Buildings, as required	N/A	Site Specific	-
Site Specific - Other	N/A	Site Specific	-
Total Site Specific Costs			NA
Installation Total			**19,232,699**
Total Direct Capital Cost, DC			**45,222,832**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	2,599,013
Construction & field expenses	20%	of purchased equip cost (B)	5,198,027
Contractor fees	10%	of purchased equip cost (B)	2,599,013
Start-up	1%	of purchased equip cost (B)	259,901
Performance test	1%	of purchased equip cost (B)	259,901
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	2,599,013
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**13,514,869**
Total Capital Investment (TCI) = DC + IC			**58,737,702**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**57,855,102**
Total Capital Investment (TCI) with Retrofit Factor	60%		**92,568,163**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	60.00	$/Hr, 2.0 hr/8 hr shift, 5650 hr/yr	84,750
Supervisor	15%	15% of Operator Costs	12,713
Maintenance			
Maintenance Labor	60.00	$/Hr, 1.0 hr/8 hr shift, 5650 hr/yr	42,375
Maintenance Materials	100%	of maintenance labor costs	42,375
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.08	$/kwh, 363.4 kW-hr, 5650 hr/yr, 73% utilization	156,065
Compressed Air	0.48	$/kscf, 2.0 scfm/kacfm, 5650 hr/yr, 73% utilization	47,841
N/A			-
SW Disposal	42.56	$/ton, 0.2 ton/hr, 5650 hr/yr, 73% utilization	51,679
Lime	167.17	$/ton, 290.7 lb/hr, 5650 hr/yr, 73% utilization	137,302
Filter Bags	249.27	$/bag, 2,952 bags, 5650 hr/yr, 73% utilization	206,684
Lost Revenue - Fly Ash			250,000
N/A			-
N/A			-
N/A			-
N/A			-
N/A			-
N/A			-
N/A			-
Total Annual Direct Operating Costs			**1,031,783**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	109,328
Administration (2% total capital costs)	2%	of total capital costs (TCI)	1,851,363
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	925,682
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	925,682
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	7,952,726
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**11,764,780**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**12,796,563**

Cleveland Cliffs - Northshore Mining Power Boiler #1
Appendix A - Four-Factor Control Cost Analysis
Table A-5: SO2 Control Spray Dry Absorber (SDA) with Baghouse (including lime slaking system)

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment: **Filter Bags**

Equipment Life	5	years	
CRF	0.2342		
Rep part cost per unit	249.27	$/bag	
Amount Required	2952	# of Bags for new baghouse	
Total Rep Parts Cost	823,565	Cost adjusted for freight & sales tax	
Installation Labor	59,035	10 min per bag, Labor + Overhead (68% = $29.65/hr)	EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**882,600**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag.
Annualized Cost	**206,684**		

Electrical Use

	Flow acfm	D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	200,800	10.00			2,053,481	Electricity demand for new baghouse
Total					2,053,481	

Reagents and Other Operating Costs

Lime Use Rate	1.30	lb-mole CaO/lb-mole SO2	290.74	lb/hr Lime
Solid Waste Disposal	1,214	ton/yr unreacted sorbent and reaction byproducts		

Operating Cost Calculations

Utilization Rate	73%	Annual Operating Hours	5,650

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	60.00	$/Hr	2.0	hr/8 hr shift	1,413	$ 84,750	$/Hr, 2.0 hr/8 hr shift, 5650 hr/yr
Supervisor	15%	of Op.			NA	$ 12,713	15% of Operator Costs
Maintenance							
Maint Labor	60.00	$/Hr	1.0	hr/8 hr shift	706	$ 42,375	$/Hr, 1.0 hr/8 hr shift, 5650 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	$ 42,375	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.076	$/kwh	363.4	kW-hr	2,053,481	$ 156,065	$/kwh, 363.4 kW-hr, 5650 hr/yr, 73% utilization
Compressed Air	0.481	$/kscf	2	scfm/kacfm	99,384	$ 47,841	$/kscf, 2.0 scfm/kacfm, 5650 hr/yr, 73% utilization
Water	0.340	$/mgal		gpm			$/mgal, 0 gpm, 5650 hr/yr, 73% utilization
SW Disposal	42.56	$/ton	0.21	ton/hr	1,214	$ 51,679	$/ton, 0.2 ton/hr, 5650 hr/yr, 73% utilization
Lime	167.17	$/ton	290.7	lb/hr	821	$ 137,302	$/ton, 290.7 lb/hr, 5650 hr/yr, 73% utilization
Filter Bags	249.27	$/bag	2,952	bags	N/A	$ 206,684	$/bag, 2,952 bags, 5650 hr/yr, 73% utilization

Appendix B

Unit-specific Screening Level Cost Summary for Power Boiler 2

Cleveland Cliffs - Northshore Mining Power Boiler #2
Appendix B - Four-Factor Control Cost Analysis
Table B-1: Cost Summary

NO_x Control Cost Summary

Control Technology	Control Eff %	Installed Capital Cost $	Annualized Operating Cost $/yr
Low NOx Burners + Over Fire Air (LNB+OFA) Coal-Fired	40%	$11,609,362	$1,725,870
Selective Non-Catalytic Reduction (SNCR)	25%	$8,917,925	$1,435,176
Selective Catalytic Reduction (SCR)	80%	$55,724,684	$5,985,367

SO_2 Control Cost Summary

Control Technology	Control Eff %	Installed Capital Cost $	Annualized Operating Cost $/yr
Dry Sorbent Injection (DSI) with Baghouse	70%	$37,737,598	$6,943,044
Spray Dry Absorber (SDA) with Baghouse	90%	$61,962,015	$13,572,909

Cleveland Cliffs - Northshore Mining Power Boiler #2
Appendix B - Four-Factor Control Cost Analysis
Table B-2: Summary of Utility, Chemical and Supply Costs

Operating Unit:	Power Boiler 2	**Study Year**	2020
Emission Unit Number	EQUI 15 / EU 002		
Stack/Vent Number	SV 002		

	2020					
Item	**Unit Cost**	**Units**	**Cost**	**Year**	**Data Source**	**Notes**
Operating Labor	60	$/hr		2020	Site-specific data	
Maintenance Labor	60	$/hr		2020	Site-specific data	
Electricity	0.076	$/kwh			EIA 2020 Avg Price Industrial Nat Gas in MN	
Natural Gas	4.98	$/kscf		NA	5-year average based on 2014-2018 gas prices on epia.gov	
Water	0.34	$/mgal	0.20	2002	2002, Section 6 Chapter 2	Adjusted for 3% inflation
Cooling Water	0.42	$/mgal	0.23	1999	2002, Section 3.1 Chapter 1	Ch 1 Carbon Absorbers, 1999 $0.15-$0.30 Avg of 22.5 and 7 yrs and 3% inflation
Compressed Air	0.48	$/kscf	0.38	2012	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1	Adjusted for 3% inflation
Chemicals & Supplies						
Lime	167.17	$/ton	140.00	2014	Site Specific	Adjusted for 3% inflation
Trona	285.00	$/ton			Vendor estimated delivered cost	
Urea 50% Solution	1.81	$/gallon	1.66	2017	EPA Control Cost Manual Chapter 7, 7th Edition default	Adjusted for 3% inflation
Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours			EPA Control Cost Manual Chapter 7, 7th Edition default	
SCR Catalyst cost ($CC_{replace}$)	248	$/cubic foot	227	2017	EPA Control Cost Manual Chapter 7, 7th Edition default	Adjusted for 3% inflation
Fabric Filter Bags	249.27	$/bag	160	2005	Northshore Mining March 2009 submittal to MPCA	Adjusted for 3% inflation
Other						
Sales Tax	6.875%			2020	Current MN sales tax rate	
Interest Rate	5.50%			2016	EPA Control Cost Manual Chapter 7, 7th Edition default	
Solid Waste Disposal	42.56	$/ton	25	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1	Adjusted for 3% inflation
Contingencies	10%	of purchased equip cost (B)			EPA Control Cost Manual Chapter 2, 7th Edition estimates contingencies from 5-15%. Assumed the mid range	
Markup on capital investment (retrofit factor)	60%				CUECost Workbook Version 1.0, USEPA Document Page 2 allows up to a 60% retrofit factor for installations in existing facilities.	
Operating Information						
Annual Op. Hrs	5,774	Hours			2017 Site-specific operating hours	
Utilization Rate	78%				Site-specific estimate, 2017 emission inventory	
Design Capacity	765.0	MMBTU/hr			Site-specific estimate	
Equipment Life	20	yrs			Assumed	
Temperature	265	Deg F			Site-specific estimate	
Moisture Content	11.0%				Site-specific estimate	
Actual Flow Rate	232,100	acfm			Site-specific estimate	
Standardized Flow Rate	163,800	scfm @ 68º F	157,508	scfm @ 32º F	Site-specific estimate	
Dry Std Flow Rate	145,700	dscfm @ 68º F			Site-specific estimate	
Fuel higher heating value (HHV)	8,826	BTU/lb			EPA Control Cost Manual Chapter 7, 7th Edition default for sub-bituminous	
Plant Elevation	764	Feet above sea level			Site Elevation	
Fuel Sulfur Content (%)	0.41	%			EPA Control Cost Manual Chapter 7, 7th Edition default for sub-bituminous	
# days boiler operates	241	days			Site Specific Data	
Technology Control Efficiency						
SDA - SO_2 Control Efficiency	90%				EPA fact sheet for flue gas desulfurization (new installations) https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf	
DSI - SO_2 Control Efficiency	70%	Trona Control Efficiency			Control efficiency is based on trona as injected reagent.	
SCR - NO_x Control Efficiency	80%				Based on engineering assessment.	
LNB+OFA- NO_x Control Efficiency	40%				Northshore Mining September 2006 submittal to MPCA	
SNCR - NO_x Performance	0.44	lb/MMBtu			EPA Control Cost Manual Chapter 7, 7th Edition, SCR Figure 1.1 *(efficiency vs inlet NOx concentration approximation (25%) reduction)*	

Cleveland Cliffs - Northshore Mining Power Boiler #2
Appendix B - Four-Factor Control Cost Analysis
Table B-3: NO$_x$ Control - Low NOx Burners (LNB) with Over-Fire Air (OFA) Coal-Fired

Operating Unit: **Power Boiler 2**

Emission Unit Number	EQUI 15 / EU 002		Stack/Vent Number	SV 002	
Desgin Capacity	765	MMBtu/hr	Standardized Flow Rate	157,508	scfm @ 32º F
Expected Utiliztion Rate	78%		Temperature	265	Deg F
Expected Annual Hours of Operation	5,774	Hours	Moisture Content	11.0%	
Annual Interest Rate	5.5%		Actual Flow Rate	232,100	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	163,800	scfm @ 68º F
			Dry Std Flow Rate	145,700	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								**2,948,468**
Purchased Equipment Total (B)	14%	of control device cost (A)						**3,357,568**
Installation - Standard Costs	95%	of purchased equip cost (B)						3,189,689
Installation - Site Specific Costs								1,218,983
Installation Total								3,189,689
Total Direct Capital Cost, DC								6,547,257
Total Indirect Capital Costs, IC	68%	of purchased equip cost (B)						5,062,104
Total Capital Investment (TCI) = DC + IC								**11,609,362**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						277,985
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						1,447,885
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**1,725,870**

Notes & Assumptions

1 Cost estimate from vendor engineering estimate scaled for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
2 Installation cost assumptions and calculation methodology based on vendor engineering estimates
3 Maintenance and replacement power costs based on vendor engineering estimate
4 Cost Effectiveness in $/ton removed is not determined because emissions in 2028 are projected to be zero.

Cleveland Cliffs - Northshore Mining Power Boiler #2
Appendix B - Four-Factor Control Cost Analysis
Table B-3: NOx Control - Low NOx Burners (LNB) with Over-Fire Air (OFA) Coal-Fired

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**2,948,468**
Purchased Equipment Costs (A)			
Instrumentation	2%	of control device cost (A)	58,969
MN Sales Taxes	6.9%	of control device cost (A)	202,707
Freight	5%	of control device cost (A)	147,423
Purchased Equipment Total (B)	14%		**3,357,568**
Installation [1]			
Foundations & supports	30%	of purchased equip cost (B)	1,007,270
Handling & erection	20%	of purchased equip cost (B)	671,514
Electrical	20%	of purchased equip cost (B)	671,514
Piping	10%	of purchased equip cost (B)	335,757
Insulation	10%	of purchased equip cost (B)	335,757
Painting	2.5%	of purchased equip cost (B)	83,939
Demolition	2.5%	of purchased equip cost (B)	83,939
Installation Subtotal Standard Expenses	95%		**3,189,689**
Installation Total			**3,189,689**
Total Direct Capital Cost, DC			**6,547,257**
Indirect Capital Costs			
Engineering, supervision	15%	of direct costs (DC)	982,089
Owner's cost	10%	of direct costs (DC)	654,726
Construction & field expenses	5%	of direct costs (DC)	327,363
Contractor fees	15%	of direct costs (DC)	982,089
Start-up and spare parts	2%	of direct costs (DC)	130,945
Performance test	1%	Engineering estimate	50,000
Model Studies	NA	of direct costs (DC)	N/A
Contingencies	20%	of direct costs (DC) and indirect costs (IC) above	1,934,894
Total Indirect Capital Costs, IC	68%	of direct costs (DC)	**5,062,104**
Total Capital Investment (TCI) = DC + IC			**11,609,362**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Allowance for funds used during construciton	10.5%	of DC + IC	1,218,983
Total Site Specific Costs			**1,218,983**
TCI with site specifics for capital recovery cost			**12,828,344**
Total Capital Investment (TCI) with Retrofit Factor	0%	No retrofit factor needed based on site-specific analysis	**12,828,344**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Maintenance labor and materials	3%	of direct capital (DC) costs	196,418
Utilities, Supplies, Replacements & Waste Management			
Replacement power from efficiency loss	NA	0.2% OFA efficiency drop per engineering estimates	81,567
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**277,985**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	117,851
Administration (2% total capital costs)	2%	of total capital costs (TCI)	256,567
Property tax (1% total capital costs)	N/A	of total capital costs (TCI)	0
Insurance (1% total capital costs)	N/A	Already included in costs above	0
Capital Recovery	8%	for a 20- year equipment life and a 5.5% interest rate	1,073,467
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,447,885**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,725,870**

Cleveland Cliffs - Northshore Mining Power Boiler #2
Appendix B - Four-Factor Control Cost Analysis
Table B-3: NOx Control - Low NOx Burners (LNB) with Over-Fire Air (OFA) Coal-Fired

Capital Recovery Factors	
Primary Installation	
Interest Rate	5.50%
Equipment Life	20 years
CRF	0.0837

Replacement Parts & Equipment:
N/A

Replacement Parts & Equipment:
N/A

Electrical Use

Reagent Use & Other Operating Costs

Operating Cost Calculations from Engineering Vendor

Operating Hours 5,774
Utilization Rate: 78%

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments

Air Pollution Control Cost Estimation Spreadsheet
For Selective Non Catalytic Reduction (SNCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Non-Catalytic Reduction (SNCR) control device. SNCR is a post-combustion control technology for reducing NOx emissions by injecting an ammonia-base reagent (urea or ammonia) into the furnace at a location where the temperature is in the appropriate range for ammonia radicals to react with NOx to form nitrogen and water.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SNCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SNCR control technology and the cost methodologies, see Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SNCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM version 6). The size and costs of the SNCR are based primarily on four parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, and the reagent consumption. This approach provides study-level estimates (±30%) of SNCR capital and annual costs. Default data in the spreadsheet is taken from the SNCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions, such as the boiler configuration and fuel type. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will reset the NSR, plant elevation, estimated equipment life, desired dollar year, cost index (to match desired dollar year), annual interest rate, unit costs for fuel, electricity, reagent, water and ash disposal, and the cost factors for maintenance cost and administrative charges. All other data entry fields will be blank.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SNCR is for new construction or retrofit of an existing boiler. 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.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you selected coal, select the type of coal burned from the drop down menu. The NOx emissions rate, weight percent coal ash and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided.

Step 4: Complete all of the cells highlighted in yellow. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.015 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SNCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SNCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.6

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 765 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 8,826 Btu/lb

*HHV value of 8826 Btu/lb is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual fuel consumption? 390,363,222

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

coal burned: Sub-Bituminous

Enter the sulfur content (%S) =

or

Select the appropriate SO_2 emission rate: Not Applicable

*The sulfur content of 0.41% is a default value. See below for data source. Enter actual value, if known.

Ash content (%Ash): percent by weight

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	241	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.58	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.44	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	0.80	

Plant Elevation	764	Feet above sea level

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Urea ▼	

Densities of typical SNCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Enter the cost data for the proposed SNCR:

Desired dollar-year	2020			
CEPCI for 2020	607.5	2019 Final CEPCI Value	541.7	2016 CEPCI
Annual Interest Rate (i)	5.50	Percent*		
Fuel ($Cost_{fuel}$)	2.13	$/MMBtu		
Reagent ($Cost_{reag}$)	1.81	$/gallon for a 50 percent solution of urea		
Water ($Cost_{water}$)	0.0051	$/gallon		
Electricity ($Cost_{elect}$)	0.0760	$/kWh		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	42.56	$/ton		

CEPCI = Chemical Engineering Plant Cost Index

* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/MMBtu)	1.89	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Ash Disposal Cost ($/ton)	48.8	Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft Demand. July 11, 2017. Available at: http://www.wastebusinessjournal.com/news/wbj20170711A.htm.	
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Percent ash content for Coal (% weight)	5.84	Average ash content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	765	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	759,279,402	lbs/year
Actual Annual fuel consumption (Mactual) =		390,363,222	lbs/year
Heat Rate Factor (HRF) =	NPHR/10 =	1.00	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.34	fraction
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	5774	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	25	percent
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO_2 Emission rate =	(%S/100)x(64/32)*($1x10^6$)/HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.03	
Atmospheric pressure at 764 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.3	psia
Retrofit Factor (RF) =	Retrofit to existing boiler	1.60	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	232	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/C_{sol} =	464	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	48.9	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	16,500	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	16.7	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	223	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	1.88	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/HHV =	12.4	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$2,632,583 in 2020 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2020 dollars
Balance of Plant Costs (BOP_{cost}) =	$4,227,360 in 2020 dollars
Total Capital Investment (TCI) =	$8,917,925 in 2020 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$2,632,583 in 2020 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2020 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$4,227,360 in 2020 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$684,733	in 2020 dollars
Indirect Annual Costs (IDAC) =	$750,443	in 2020 dollars
Total annual costs (TAC) = DAC + IDAC	$1,435,176	in 2020 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$133,769	in 2020 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$512,408	in 2020 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$7,337	in 2020 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$6,591	in 2020 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$23,099	in 2020 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$1,529	in 2020 dollars
Direct Annual Cost =		$684,733	in 2020 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$4,013	in 2020 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$746,430	in 2020 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$750,443	in 2020 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,435,176	per year in 2020 dollars
NOx Removed =	N/A	tons/year
Cost Effectiveness =	N/A	per ton of NOx removed in 2020 dollars

Note: Cost Effectiveness is not determined because emissions in 2028 are projected to be zero.

Cleveland Cliffs - Northshore Mining Power Boiler #2
Appendix B - Four-Factor Control Cost Analysis
Table B-4: NO$_x$ Control - Selective Catalytic Reduction

Operating Unit: **Power Boiler 2**

Emission Unit Number	EQUI 15 / EU 002		Stack/Vent Number	SV 002	
Design Capacity	765	mmbtu/hr	Standardized Flow Rate	157,508	scfm @ 32º F
Expected Utilization Rate	78%		Temperature	265	Deg F
Expected Annual Hours of Operation	5,774	Hours	Moisture Content	11.0%	
Annual Interest Rate	5.5%		Actual Flow Rate	232,100	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	163,800	scfm @ 68º F
			Dry Std Flow Rate	145,700	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs	EPRI Correlation							
Total Capital Investment (TCI) with Retrofit								55,724,684
								55,724,684
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						**1,316,135**
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						**4,669,232**
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**5,985,367**

Notes & Assumptions

1. Estimated Equipment Cost per EPA Air Pollution Control Cost Manual 7th Ed SCR Control Cost Spreadsheet
2. Costs scaled to current dollars from the Chemical Engineering Plant Cost Index (CEPCI)
3. Cost Effectiveness in $/ton removed is not determined because emissions in 2028 are projected to be zero.

Cleveland Cliffs - Northshore Mining Power Boiler #2
Appendix B - Four-Factor Control Cost Analysis
Table B-4: NOx Control - Selective Catalytic Reduction

CAPITAL COSTS			
SCR Capital Costs (SCRcost)		*Refer to the SCR Cost Estimate tab*	32,318,901
Reagent Preparation Costs (RPC)		*Refer to the SCR Cost Estimate tab*	4,392,698
Air Pre-Heater Costs (APHC)		*Refer to the SCR Cost Estimate tab*	-
Balance of Plant Costs (BPC)		*Refer to the SCR Cost Estimate tab*	6,153,542
Retrofit factor	60%	*of TCI, see SCR Cost Estimate tab*	
Total Capital Investment (TCI)			**55,724,684**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Maintenance			
Annual Maintenance Cost =		*Refer to the SCR Cost Estimate tab*	278,623
Utilities, Supplies, Replacements & Waste Management			
Annual Electricity Cost =		*Refer to the SCR Cost Estimate tab*	191,978
Annual Catalyst Replacement Cost =		*Refer to the SCR Cost Estimate tab*	308,662
Annual Reagent Cost =		*Refer to the SCR Cost Estimate tab*	536,872
Total Annual Direct Operating Costs			**1,316,135**
Indirect Operating Costs			
Administrative Charges (AC) =		*Refer to the SCR Cost Estimate tab*	5,076
Capital Recovery Costs (CR)=	0.0837	*Refer to the SCR Cost Estimate tab*	4,664,156
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**4,669,232**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**5,985,367**

Cleveland Cliffs - Northshore Mining Power Boiler #2
Appendix B - Four-Factor Control Cost Analysis
Table B-4: NOx Control - Selective Catalytic Reduction

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catayst - Refer to the SCR Cost Estimate Tab

Reagent Use

Refer to the SCR Cost Estimate tab

Operating Cost Calculations	**Annual hours of operation:**	**5,774**
Refer to the SCR Cost Estimate tab	**Utilization Rate:**	**78%**

Air Pollution Control Cost Estimation Spreadsheet
For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards

(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO_x emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO_x within a specific temperature range to produce N_2 and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 6). For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retrofit of an existing boiler. 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.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.6

* NOTE: You must document why a retrofit factor of 1.6 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	765	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	8,826	Btu/lb

*HHV value of 8826 Btu/lb is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual fuel consumption?	390,363,222	
Operating Hours	5,774	323,950,000.00
Enter the net plant heat input rate (NPHR)	10	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	764	Feet above sea level

coal burned: Sub-Bituminous

Enter the sulfur content (%S) =

*The sulfur content of 0.41% is a default value. See below for data source. Enter actual value, if known.

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	
Bituminous	
Sub-Bituminous	
Lignite	

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

○ Method 1
● Method 2
○ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})		days
Number of days the boiler operates (t_{plant})		days
Inlet NO_x Emissions (NOx_{in}) to SCR		lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR		lb/MMBtu
Stoichiometric Ratio Factor (SRF)		

*The SRF value of 0.525 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})		
Number of catalyst layers (R_{layer})		
Number of empty catalyst layers (R_{empty})		
Ammonia Slip (Slip) provided by vendor		ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)		Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)		acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)		°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})		ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	50	percent*
Density of reagent as stored (ρ_{stored})	71	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 50% and density of 71 lbs/cft are default values for urea reagent. User should enter actual values for reagent, if different from the default values provided.

Select the reagent used: Urea ▼

Enter the cost data for the proposed SCR:

Desired dollar-year				
CEPCI for 2019		2019 CEPCI Final Value	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)		Percent*		* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent (Cost_{reag})		$/gallon for 50% urea		
Electricity (Cost_{elect})		$/kWh		
Catalyst cost ($\text{CC}_{replace}$)		$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst		
Operator Labor Rate		$/hour (including benefits)*		* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day		hours/day*		* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SCR Cost Development Methodology, Chapter 5, Attachment 5-3, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-3_scr_cost_development_methodology.pdf	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	765	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	759,279,402	lbs/year
Actual Annual fuel consumption (Mactual) =		390,363,222	lbs/year
Heat Rate Factor (HRF) =	NPHR/10 =	1.00	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.514	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	5,774	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.0	percent
NO_x removal factor (NRF) =	EF/80 =	1.00	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	355,523	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	106.69	/hour
Residence Time	1/V_{space}	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.03	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.3	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.60	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.2303	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	3,332.24	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	370	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	426	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	20.6	feet
Reactor height =	$(R_{layer} + R_{empty}) \times (7ft + h_{layer}) + 9ft$	53	feet

Reagent Data:

Type of reagent used: Urea

Molecular Weight of Reagent (MW) = 60.06 g/mole

Density = 71 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times EF \times SRF \times MW_R)/MW_{NOx}$ =	243	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/Csol$ =	487	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density	51	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24)$/Reagent Density =	17,300	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i\,(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	$A \times 1{,}000 \times 0.0056 \times (CoalF \times HRF)^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	437.48	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$32,318,901	in 2019 dollars
Reagent Preparation Cost (RPC) =	$4,392,698	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2019 dollars
Balance of Plant Costs (BPC) =	$6,153,542	in 2019 dollars
Total Capital Investment (TCI) =	$55,724,684	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) = $32,318,901 in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) = $4,392,698 in 2019 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) = $0 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529{,}000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) = $6,153,542 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,316,135 in 2019 dollars
Indirect Annual Costs (IDAC) =	$4,669,232 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$5,985,367 in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$278,623 in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$536,872 in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$191,978 in 2019 dollars
Annual Catalyst Replacement Cost =		$308,662 in 2019 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.		
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x $(CC_{replace}/R_{layer})$ x FWF	* Calculation Method 2 selected.
Method 2 (for coal-fired industrial boilers):	$(Q_B/NPHR)$ x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x $(CC_{replace})$ x 35.3	
Direct Annual Cost =		$1,316,135 in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$5,076 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$4,664,156 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$4,669,232 in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$5,985,367 per year in 2019 dollars
NOx Removed =	N/A tons/year
Cost Effectiveness =	N/A per ton of NOx removed in 2019 dollars

Note: Cost Effectiveness is not determined because emissions in 2028 are projected to be zero.

Cleveland Cliffs - Northshore Mining Power Boiler #2
Appendix B - Four-Factor Control Cost Analysis
Table B-5: SO2 Control Dry Sorbent Injection (DSI) with Baghouse (including injection system)

Operating Unit: **Power Boiler 2**

Emission Unit Number			Stack/Vent Number		
Design Capacity	765	MMBtu/hr	Standardized Flow Rate	157,508	scfm @ 32º F
Utilization Rate	78%		Exhaust Temperature	265	Deg F
Annual Operating Hours	5,774	hr/yr	Exhaust Moisture Content	11.0%	
Annual Interest Rate	5.50%		Actual Flow Rate	232,100	acfm
Control Equipment Life	20	yrs	Standardized Flow Rate	163,800	scfm @ 68º F
Plant Elevation	764	ft	Dry Std Flow Rate	145,700	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs						
Direct Capital Costs						
Purchased Equipment (A)						**8,933,488**
Purchased Equipment Total (B)	22%	of control device cost (A)				**10,887,688**
Installation - Standard Costs	74%	of purchased equip cost (B)				8,056,889
Installation - Site Specific Costs						N/A
Installation Total						8,056,889
Total Direct Capital Cost, DC						18,944,577
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)				5,661,598
Total Capital Investment (TCI) = DC + IC						**23,585,999**
Adjusted TCI for Replacement Parts						23,585,999
Total Capital Investment (TCI) with Retrofit Factor						**37,737,598**
Operating Costs						
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.				1,925,055
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost				5,017,989
Total Annual Cost (Annualized Capital Cost + Operating Cost)						**6,943,044**

Notes & Assumptions

1 Baghouse cost estimate from 2008 vendor data for 165,000 acfm baghouse, (Northshore Mining March 2009 submittal to MPCA)
2 Purchased equipment costs include anciliary equipment
3 Costs scaled up to design airflow using the 6/10 power law
4 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
5 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1
6 Cost Effectiveness in $/ton removed is not determined because emissions in 2028 are projected to be zero.

Cleveland Cliffs - Northshore Mining Power Boiler #2
Appendix B - Four-Factor Control Cost Analysis
Table B-5: SO2 Control Dry Sorbent Injection (DSI) with Baghouse (including injection system)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) [(1)]			**8,933,488**
Purchased Equipment Costs (A) - Injection System + auxiliary equipment, EC			
Instrumentation	10%	Included in vendor estimate	893,349
State Sales Taxes	6.9%	of control device cost (A)	614,177
Freight	5%	of control device cost (A)	446,674
Purchased Equipment Total (B)	22%		**10,887,688**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	435,508
Handling & erection	50%	of purchased equip cost (B)	5,443,844
Electrical	8%	of purchased equip cost (B)	871,015
Piping	1%	of purchased equip cost (B)	108,877
Insulation	7%	of purchased equip cost (B)	762,138
Painting	4%	Included in vendor estimate	435,508
Installation Subtotal Standard Expenses	74%		**8,056,889**
Other Specific Costs (see summary)			
Site Preparation, as required	N/A	Site Specific	
Buildings, as required	N/A	Site Specific	
Lost Production for Tie-In	N/A	Site Specific	
Total Site Specific Costs			N/A
Installation Total			**8,056,889**
Total Direct Capital Cost, DC			**18,944,577**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	1,088,769
Construction & field expenses	20%	of purchased equip cost (B)	2,177,538
Contractor fees	10%	of purchased equip cost (B)	1,088,769
Start-up	1%	of purchased equip cost (B)	108,877
Performance test	1%	of purchased equip cost (B)	108,877
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	1,088,769
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**5,661,598**
Total Capital Investment (TCI) = DC + IC			**24,606,175**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**23,585,999**
Total Capital Investment (TCI) with Retrofit Factor	60%		**37,737,598**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	60.00	$/Hr	86,610
Supervisor	0.15	of Op Labor	12,992
Maintenance			
Maintenance Labor	60.00	$/Hr	43,305
Maintenance Materials	100	% of Maintenance Labor	43,305
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.08	$/kwh, 252.1 kW-hr, 5774 hr/yr, 78% utilization	110,610
N/A			-
Compressed Air	0.48	$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization	60,382
N/A			-
Solid Waste Disposal	42.56	$/ton, 0.6 ton/hr, 5774 hr/yr, 78% utilization	115,574
Trona	285.00	$/ton, 1,501.1 lb/hr, 5774 hr/yr, 78% utilization	963,375
Filter Bags	249.27	$/bag, 3,412 bags, 5774 hr/yr, 78% utilization	238,901
Lost Revenue - Fly Ash			250,000
N/A			-
N/A			-
N/A			-
Total Annual Direct Operating Costs			**1,925,055**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	111,727
Administration (2% total capital costs)	2%	of total capital costs (TCI)	754,752
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	377,376
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	377,376
Capital Recovery	0.0837	for a 20-year equipment life and a 5.5% interest rate	3,157,857
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery costs	**5,017,989**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**6,943,044**

Cleveland Cliffs - Northshore Mining Power Boiler #2
Appendix B - Four-Factor Control Cost Analysis
Table B-5: SO2 Control Dry Sorbent Injection (DSI) with Baghouse (including injection system)

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:	**Filter Bags**	
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	249.27	$/bag
Amount Required	3412	# of Bags for new baghouse
Total Rep Parts Cost	951,939	Cost adjusted for freight, sales tax, and bag disposal
Installation Labor	68,237	20 min per bag
Total Installed Cost	**1,020,177**	
Annualized Cost	**238,901**	

Electrical Use

	Flow acfm	D P in H2O	kWhr/yr	
Blower	232,100	6.00	1,455,398	Electricity for new baghouse
Total			1,455,398	

Reagent Use & Other Operating Costs

Trona use - 1.5 NSR	270.18	lb/hr SO2	1501.10	lb/hr Trona
Solid Waste Disposal	3,481	ton/yr DSI unreacted sorbent and reaction byproducts		

Operating Cost Calculations

Utilization Rate	78%	Annual Operating Hours	5,774

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	60.00	$/Hr	2.0	hr/8 hr shift	1,444	$ 86,610	$/Hr, 2.0 hr/8 hr shift, 1,444 hr/yr
Supervisor	15%	of Op Labor			NA	$ 12,992	% of Operator Costs
Maintenance							
Maint Labor	60.00	$/Hr	1.0	hr/8 hr shift	722	$ 43,305	$/Hr, 1.0 hr/8 hr shift, 722 hr/yr
Maint Mtls	100%	of Maintenance Labor			NA	$ 43,305	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.076	$/kwh	252.1	kW-hr	1,455,398	$ 110,610	$/kwh, 252.1 kW-hr, 5774 hr/yr, 78% utilization
Water			N/A	gpm			
Compressed Air	0.481	$/kscf	2.0	scfm/kacfm	125,438	$ 60,382	$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization
Cooling Water			N/A	gpm			
Solid Waste Disposal	42.56	$/ton	0.6	ton/hr	2,716	$ 115,574	$/ton, 0.6 ton/hr, 5774 hr/yr, 78% utilization
Trona	285.00	$/ton	1,501.1	lb/hr	3,380	$ 963,375	$/ton, 1,501.1 lb/hr, 5774 hr/yr, 78% utilization
Filter Bags	249.27	$/bag	3,412	bags	N/A	$ 238,901	$/bag, 3,412 bags, 5774 hr/yr, 78% utilization

Cleveland Cliffs - Northshore Mining Power Boiler #2
Appendix B - Four-Factor Control Cost Analysis
Table B-6: SO2 Control Spray Dry Absorber (SDA) with Baghouse (including lime slaking system)

Operating Unit: **Power Boiler 2**

Emission Unit Number	EQUI 15 / EU 002		Stack/Vent Number	SV 002	
Design Capacity	765	MMBtu/hr	Standardized Flow Rate	157,508	scfm @ 32º F
Utilization Rate	78%		Temperature	265	Deg F
Annual Operating Hours	5,774	Hours	Moisture Content	11.0%	
Annual Interest Rate	5.5%		Actual Flow Rate	232,100	acfm
Equipment Life	20	yrs	Standardized Flow Rate	163,800	scfm @ 68º F
			Dry Std Flow Rate	145,700	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs									
Direct Capital Costs									
Purchased Equipment (A)									**22,495,853**
Purchased Equipment Total (B)	22%	of control device cost (A)							**27,416,821**
Installation - Standard Costs	74%	of purchased equip cost (B)							20,288,447
Installation - Site Specific Costs									NA
Installation Total									20,288,447
Total Direct Capital Cost, DC									47,705,268
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)							14,256,747
Total Capital Investment (TCI) = DC + IC									**61,962,015**
Adjusted TCI for Replacment Parts									**60,941,838**
TCI with Retrofit Factor									**97,506,941**
Operating Costs									
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.							1,162,688
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost							12,410,221
Total Annual Cost (Annualized Capital Cost + Operating Cost)									**13,572,909**

Notes & Assumptions

1 Capital cost estimate based on flow rate of 300,000 scfm from Northshore Mining Powerhouse #2 March 2009 submittal including anciliary equipment
2 Costs scaled up to design airflow using the 6/10 power law
3 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1
5 Cost Effectiveness in $/ton removed is not determined because emissions in 2028 are projected to be zero.

Cleveland Cliffs - Northshore Mining Power Boiler #2
Appendix B - Four-Factor Control Cost Analysis
Table B-6: SO2 Control Spray Dry Absorber (SDA) with Baghouse (including lime slaking system)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) [(1)]			**22,495,853**
Purchased Equipment Costs (A) - Absorber + packing + auxiliary equipment, EC			
Instrumentation	10%	of control device cost (A)	2,249,585
State Sales Taxes	6.9%	of control device cost (A)	1,546,590
Freight	5%	of control device cost (A)	1,124,793
Purchased Equipment Total (B)	22%		**27,416,821**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	1,096,673
Handling & erection	50%	of purchased equip cost (B)	13,708,410
Electrical	8%	of purchased equip cost (B)	2,193,346
Piping	1%	of purchased equip cost (B)	274,168
Insulation	7%	of purchased equip cost (B)	1,919,177
Painting	4%	of purchased equip cost (B)	1,096,673
Installation Subtotal Standard Expenses	74%		**20,288,447**
Other Specific Costs (see summary)			
Site Preparation, as required	N/A	Site Specific	-
Buildings, as required	N/A	Site Specific	-
Site Specific - Other	N/A	Site Specific	-
Total Site Specific Costs			NA
Installation Total			**20,288,447**
Total Direct Capital Cost, DC			**47,705,268**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	2,741,682
Construction & field expenses	20%	of purchased equip cost (B)	5,483,364
Contractor fees	10%	of purchased equip cost (B)	2,741,682
Start-up	1%	of purchased equip cost (B)	274,168
Performance test	1%	of purchased equip cost (B)	274,168
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	2,741,682
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**14,256,747**
Total Capital Investment (TCI) = DC + IC			**61,962,015**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**60,941,838**
Total Capital Investment (TCI) with Retrofit Factor	60%		**97,506,941**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	60.00	$/Hr, 2.0 hr/8 hr shift, 5774 hr/yr	86,610
Supervisor	15%	15% of Operator Costs	12,992
Maintenance			
Maintenance Labor	60.00	$/Hr, 1.0 hr/8 hr shift, 5774 hr/yr	43,305
Maintenance Materials	100%	of maintenance labor costs	43,305
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.08	$/kwh, 420.1 kW-hr, 5774 hr/yr, 78% utilization	184,350
Compressed Air	0.48	$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization	60,382
N/A			-
SW Disposal	42.56	$/ton, 0.3 ton/hr, 5774 hr/yr, 78% utilization	66,408
Lime	167.17	$/ton, 365.6 lb/hr, 5774 hr/yr, 78% utilization	176,434
Filter Bags	249.27	$/bag, 3,412 bags, 5774 hr/yr, 78% utilization	238,901
Lost Revenue - Fly Ash			250,000
N/A			-
N/A			-
N/A			-
N/A			-
N/A			-
N/A			-
N/A			-
Total Annual Direct Operating Costs			**1,162,688**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	111,727
Administration (2% total capital costs)	2%	of total capital costs (TCI)	1,950,139
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	975,069
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	975,069
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	8,398,217
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**12,410,221**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**13,572,909**

Cleveland Cliffs - Northshore Mining Power Boiler #2
Appendix B - Four-Factor Control Cost Analysis
Table B-6: SO2 Control Spray Dry Absorber (SDA) with Baghouse (including lime slaking system)

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:	**Filter Bags**		
Equipment Life	5	years	
CRF	0.2342		
Rep part cost per unit	249.27	$/bag	
Amount Required	3412	# of Bags for new baghouse	
Total Rep Parts Cost	951,939	Cost adjusted for freight & sales tax	
Installation Labor	68,237	10 min per bag, Labor + Overhead (68% = $29.65/hr)	EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**1,020,177**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag.
Annualized Cost	**238,901**		

Electrical Use

	Flow acfm	D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	232,100	10.00			2,425,663	Electricity demand for new baghouse
Total					2,425,663	

Reagents and Other Operating Costs

Lime Use Rate	1.30	lb-mole CaO/lb-mole SO2	365.58	lb/hr Lime
Solid Waste Disposal	1,560	ton/yr unreacted sorbent and reaction byproducts		

Operating Cost Calculations

Utilization Rate	78%	Annual Operating Hours	5,774

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	60.00	$/Hr	2.0	hr/8 hr shift	1,444	$ 86,610	$/Hr, 2.0 hr/8 hr shift, 5774 hr/yr
Supervisor	15%	of Op.			NA	$ 12,992	15% of Operator Costs
Maintenance							
Maint Labor	60.00	$/Hr	1.0	hr/8 hr shift	722	$ 43,305	$/Hr, 1.0 hr/8 hr shift, 5774 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	$ 43,305	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.076	$/kwh	420.1	kW-hr	2,425,663	$ 184,350	$/kwh, 420.1 kW-hr, 5774 hr/yr, 78% utilization
Compressed Air	0.481	$/kscf	2	scfm/kacfm	125,438	$ 60,382	$/kscf, 2.0 scfm/kacfm, 5774 hr/yr, 78% utilization
Water	0.340	$/mgal		gpm			$/mgal, 0 gpm, 5774 hr/yr, 78% utilization
SW Disposal	42.56	$/ton	0.27	ton/hr	1,560	$ 66,408	$/ton, 0.3 ton/hr, 5774 hr/yr, 78% utilization
Lime	167.17	$/ton	365.6	lb/hr	1,055	$ 176,434	$/ton, 365.6 lb/hr, 5774 hr/yr, 78% utilization
Filter Bags	249.27	$/bag	3,412	bags	N/A	$ 238,901	$/bag, 3,412 bags, 5774 hr/yr, 78% utilization

Appendix C

Submittals to MPCA Regarding Indurating Furnaces 11 and 12

CLIFFS

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July 6, 2020

Mr. Hassan M. Bouchareb
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155-4194

Re: Response to Request for Information – Regional Haze Rule, Reasonable Progress, Four Factor Analysis for Indurating Furnaces 11 and 12 at Northshore Mining Company

Dear Mr. Bouchareb:

This letter is in response to the Minnesota Pollution Control Agency's (MPCA's) February 24, 2020 request for information (RFI) letter sent to Cleveland-Cliffs Inc. Northshore Mining Company (Northshore). The February 24, 2020 RFI stated that Northshore emission units were identified as a significant source of NO_X and SO_2 and are located close enough to Voyageurs National Park and Boundary Waters Canoe Area Wilderness to potentially cause or contribute to visibility impairment in these Class I areas. Therefore, the MPCA requested Northshore to submit a "four-factor analysis" by July 31, 2020 for the emission units identified in Table 1 for NOx and SO_2.

Table 1: Identified Emission Units

Unit	Unit ID
Indurating Furnace 11	EQUI 126 & EQUI 127/ EU100 & EU104
Indurating Furnace 12	EQUI 128 & EQUI 129 / EU110 & EU1114
Power Boiler 1	EQUI 14 / EU001
Power Boiler 2	EQUI 15 / EU002

The "four-factor analysis" is a control equipment evaluation, similar to the Best Available Control Technology (BACT) and Best Available Retrofit Technology (BART) evaluations, that must address the four statutory factors laid out in 40 CFR 51.308(f)(2)(i):

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

The MPCA intends to use the four-factor analyses to evaluate additional control measures as part of the development of the State Implementation Plan (SIP), which is due to be submitted to United States Environmental Protection Agency (USEPA) by July 31, 2021. The SIP will be prepared to address the second regional haze implementation period, which ends in 2028.

This letter considers whether a four-factor analysis is warranted for Northshore's indurating furnaces because the furnaces can be classified as an "effectively controlled" source for NO_x and SO_2. The MPCA can exclude such sources for evaluation per the regulatory requirements of the Regional Haze Rule and the United States Environmental Protection Agency (USEPA) August 20, 2019 Regional Haze Guidance Memorandum (2019 RH SIP Guidance)[1].

In Section II.B.3.f of the 2019 RH SIP Guidance[2], the USEPA acknowledges that states may forgo requiring facilities to complete the detailed four-factor analysis:

> *"It may be reasonable for a state not to select an effectively controlled source. A source may already have effective controls in place as a result of a previous regional haze SIP or to meet another CAA requirement."*[3]

The associated rationale is that:

> "*…it is reasonable to assume for the purposes of efficiency and prioritization that a full four-factor analysis would likely result in the conclusion that no further controls are necessary*"[4] to make reasonable progress towards reducing visibility impairments at Class I areas.

Section II.B.4.h. of the 2019 RH SIP Guidance[5] states,

> *"It may be appropriate for a state to rely on a previous BART analysis or reasonable progress analysis for the characterization of a factor, for example information developed in the first implementation period on the availability, cost, and effectiveness of controls for a particular source, if the previous analysis was sound and no significant new information is available."*

The 2019 RH SIP Guidance identified example scenarios and described the associated rationale for why the sources are "effectively controlled" and that states can exclude similar sources from needing to complete a four-factor analysis. The USEPA stated "*BART-eligible units that installed and began operating controls to meet BART emission limits for the first implementation period*" may be "effectively controlled"

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[1] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[2] Ibid, page 11.

[3] Ibid, page 22.

[4] Ibid, page 23.

[5] Ibid, page 28.

for the associated pollutants.[6] The USEPA notes, "*it may be unlikely that there will be further available reasonable controls for such sources.*"[7] However, the USEPA adds that, "*states may not categorically exclude all BART-eligible sources, or all sources that installed BART control, as candidates for selection for analysis of control measures.*"[8] The USEPA further notes that, "*a state might, however, have a different, reasonable basis for not selecting such sources* [sources for which existing controls were determined to be BART] *for control measure analysis.*"

As described below, Indurating Furnaces 11 and 12 meet the "effectively controlled" source example scenario for units with BART NOx and SO_2 emission limits which the USEPA concluded that states could exclude from completing a four-factor analysis.

Process Description

Indurating Furnaces 11 and 12 are straight grate furnaces in which pellets move through the entire furnace on a traveling grate. The pellet hardening and oxidation section of the indurating furnace is designed to operate at 2,400 °F. This temperature is required to meet taconite pellet product specifications. Fuel combustion in the induration furnace is carried out at 300 percent to 400 percent excess air to provide sufficient oxygen for pellet oxidation.

Air is used for combustion, pellet cooling, and as a source of oxygen for pellet oxidation. Due to the high-energy demands of the induration process, indurating furnaces have been designed to recover as much heat as possible using hot exhaust gases to heat up incoming pellets. Pellet drying and preheat zones are heated with the hot gases generated in the pellet hardening/oxidation section and the pellet cooler sections. Each of these sections is designed to maximize heat recovery within process constraints. The pellet coolers are also used to preheat combustion air so more of the fuel's energy is directed to the process instead of heating ambient air to combustion temperatures.

Indurating Furnaces 11 and 12 are permitted to burn natural gas and fuel oil. SO_2 emissions are controlled by wet walled electrostatic precipitators (WWESP) using caustic reagent to offset acid conditions.

BART-required Control Equipment Installation Scenario

Indurating Furnaces 11 and 12 were BART-eligible units and BART limits were established during the first implementation phase. The 30 day-rolling average BART limits of 1.2-1.5lb NOx/MMBtu for each furnace (fuel dependent) and 39.0 lb SO_2/hr for both furnaces combined were established in the final Federal Implementation Plan (FIP) dated February 6, 2013[9]. The BART limits from the FIP are shown in Table 2.

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[6] Ibid, page 25.

[7] Ibid.

[8] Ibid.

[9] Federal Register/ Vol. 78. No. 25, February 6, 2013, EPA-R05-OAR-2010-0037 beginning on page 8706.

Table 2 BART NOx and SO_2 Emission Limits

Unit	Unit ID	NOx Limit (lb/MMBtu)	SO_2 Limit (lb/hr)
Indurating Furnace 11	EQUI 126 & EQUI 127/ EU100 & EU104	1.2-1.5	39
Indurating Furnace 12	EQUI 128 & EQUI 129 / EU110 & EU1114		

Indurating Furnaces 11 and 12 did not require installation of additional control equipment to meet the FIP NOx limits because the furnaces design inherently results in low NOx development. The Northshore furnaces emit the lowest tons of NOx per long ton product of any taconite producer making similar pellets. Northshore's furnaces are of an early vintage, which utilizes numerous burners critically located to supply heat to the various furnace sections. The burner layout limits production capability for the size of the furnace. This furnace design is not used by any other taconite producer. An inherent design that prevents formation of the pollutants far exceeds add-on controls that could result in environmental impacts such as higher collateral carbon monoxide formation. In accordance with the FIP, Northshore has continued to operate the indurating furnaces in compliance with the FIP NOx emission limits. Thus, the indurating furnaces are considered "effectively controlled" sources in accordance with the 2019 Guidance and can reasonably be excluded from the requirement to prepare and submit a four-factor analysis for NOx.

Northshore's furnaces are only capable of burning natural gas and fuel oil; with natural gas as the primary fuel. Since natural gas is low in sulfur, the primary source of SO_2 emissions is from trace amounts of sulfur in the iron concentrate and binding agents. Sulfur is also present in fuel oil, if used. Both lines are controlled by WWESPs using caustic reagent. Stack testing using natural gas fuel has demonstrated the WWESP effectively removes SO_2 to one to two parts per million in the exhaust. The USEPA concluded in the 2013 FIP.[10] that because Northshore is burning natural gas and fuel oil, additional SO_2 controls are not economically reasonable and are therefore, not necessary for BART. In accordance with the FIP, Northshore has continued to operate the BART SO_2 control measures and is complying with the FIP SO_2 emission limits. Thus, the indurating furnaces are considered "effectively controlled" sources in accordance with the 2019 RH SIP Guidance and can reasonably be excluded from the requirement to prepare and submit a four-factor analysis for SO_2.

The indurating furnaces meet the USEPA's scenario for effectively controlled units because:

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[10] Approval and Promulgation of Air Quality Implementation Plans; States of Minnesota and Michigan; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze; Final Rule. 78 Fed. Reg. 8706 (February 6, 2013)

- The indurating furnaces are BART-eligible units, as determined by Minnesota's December 2009 Regional Haze Plan, and are regulated under 40 CFR 52.1235 (Approval and Promulgation of Implementation Plans – Subpart Y Minnesota – Regional Haze)
- The indurating furnaces have controls and must "meet BART emission limits for the first implementation period" for NOx and SO_2
- In 2013, EPA promulgated a FIP that included, among other things, BART requirements to effectively control NOx and SO_2 for the Northshore indurating furnaces.
- No significant new control technology is available for indurating furnaces since the previous BART analysis.

Northshore is requesting that Indurating Furnaces 11 and 12 be excluded from the request to prepare a four-factor analysis. We are confident a full four-factor analysis would result in the conclusion that no further controls are necessary for the furnaces. Northshore will complete a Four Factor Analysis for Power Boilers 1 and 2 by July 31, 2020. Because of MPCA's request for completion of the Four Factor Analysis by July 31, 2020, Northshore is requesting a response from MPCA as soon as possible regarding this request. Thank you for your consideration.

Sincerely,

Andrea Hayden
Environmental Manager, Northshore Mining Company

cc: Paul Carlson – Northshore
Jennifer Ramsdell – Northshore
Jason Aagenes – Cleveland-Cliffs
Teresa Kinder – Barr Engineering
Julie Miller – Barr Engineering

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July 30, 2020

Mr. Hassan M. Bouchareb
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155-4194

Re: Follow Up to Response to Request for Information – Regional Haze Rule, Reasonable Progress, Four Factor Analysis for Indurating Furnaces 11 and 12 at Northshore Mining Company

Dear Mr. Bouchareb:

This letter is in response to the Minnesota Pollution Control Agency's (MPCA) email to Northshore Mining Company (Northshore) dated July 28, 2020 regarding the determination on whether Indurating Furnaces 11 and 12 can be considered effectively controlled. MPCA's email reads as follows:

Please provide a short overview of the different emission reduction opportunities evaluated at part of the Taconite FIP for Northshore. I'm specifically looking for:

- *Each reduction measure that was evaluated for NOX/SO2 control within the FIP;*
- *Whether the measure was eliminated from consideration based on technical feasibility;*
- *Whether the measure was eliminated from consideration based on cost-effectiveness; and*
- *Whether or not these determinations have materially changed since they were completed.*

Background

On August 15, 2012, the Environmental Protection Agency (EPA) proposed the Regional Haze Federal Implementation Plan (FIP) to address best available retrofit technology (BART) for taconite plants in Minnesota and Michigan.[1] The proposed FIP contained a BART analysis for Northshore's Indurating Furnaces 11 and 12. EPA's FIP was informed by Northshore's submittal to the MPCA on September 6, 2006, "Northshore Mining Company Analysis of Best Available Retrofit Technology (BART)" [2006 BART Analysis][2]. The information used for the Taconite FIP is summarized in the following paragraphs.

NOx BART Analysis

The following NOx retrofit control technologies were identified for indurating furnaces in the FIP:

- External Flue Gas Recirculation,
- Low-NOx Burners,
- Induced Flue Gas Recirculation Burners,

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[1] Approval and Promulgation of Implementation Plans; States of Minnesota and Michigan; Regional Haze Federal Implementation Plan. 77 Fed. Reg. 49308. (proposed August 15, 2012).

[2] https://www.pca.state.mn.us/sites/default/files/bart-facility-northshore.pdf

- Energy Efficiency Projects,
- Ported Kilns,
- Alternate Fuels, and
- Selective Catalytic Reduction (SCR).

Table 1 summarizes the technologies that were eliminated from consideration based on technical feasibility.

Table 1 Potential NOx Emission Control Measures Technical Feasibility Conclusions[3]

NO_X Control Measure	Technically Feasible for Straight Grate Furnace?
Pre-Combustion, Combustion, or Operational Controls	
LNB	No – Already required under FIP
EFGR	No
IFGR	No
Ported Kilns	No
Energy Efficiency Projects	No
Alternate Fuels	No
Post-Combustion Controls	
SCR – Pre-WWESP	No
SCR – Post-WWESP with Conventional Duct Burner Reheat	Potentially

In the proposed FIP, EPA states that U.S. Steel documented the infeasibility of SCR controls. In its 2006 BART Analysis, Northshore identified SCR with conventional reheat as potentially technically feasible. SCR with conventional reheat was eliminated from consideration based on cost-effectiveness in the 2006 BART Analysis. The annualized control cost was expected to be over $200,000 per ton for each furnace.

In the final FIP dated February 6, 2013, EPA established a NOx limit of 1.2 lbs/MMBtu on a 30-day rolling average for the furnaces when natural gas is used as fuel.[4] The BART limit is based on the expected control achieved using low NOx burners. However, as described in the letter to MPCA dated July 6, 2020, Indurating Furnaces 11 and 12 did not require actual installation of low NOx burners to meet BART NOx limits because the furnaces design inherently results in low NOx development.

NOx control technologies for indurating furnaces have not materially changed since the previous BART analysis. The furnaces are effectively controlled to the same level as low NOx burners. The furnaces' designs would not allow for changes in burner technology that would further reduce NOx emissions. The cost of SCR with conventional reheat has not significantly changed since the previous BART analysis; therefore, the cost effectiveness is expected to be far too high to implement SCR technology. The

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[3] Ibid., 49315.

[4] Approval and Promulgation of Air Quality Implementation Plans; States of Minnesota and Michigan; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze. 78 Fed. Reg. 8706. (February 6, 2013).

technical feasibility determinations of the other technologies listed above has not changed. No new NOx retrofit control technologies have been successfully installed on taconite indurating furnaces since the previous BART analysis.

SO_2 BART Analysis

Both furnaces are controlled by wet-walled electrostatic precipitators (WWESP) using caustic reagent. The following SO_2 retrofit control technologies were identified for indurating furnaces in the FIP:

- Wet-Walled Electrostatic Precipitator,
- Wet Scrubbing,
- Dry Sorbent Injection (DSI),
- Spray Dryer Absorption (SDA),
- Energy Efficiency Projects,
- Alternate Fuels, and
- Coal Drying.

Table 2 summarizes the technologies that were eliminated from consideration based on technical feasibility.

Table 2 Potential SO_2 Emission Control Measures Technical Feasibility Conclusions[5]

SO_2 Control Measure	Technically Feasible for Straight Grate Furnace?
Pre-Combustion, Combustion, or Operational Controls	
Energy Efficiency Projects	No
Alternate Fuels	No
Coal Drying	No
Post-Combustion Controls	
WWESP - Secondary	Yes
Wet Scrubbing – Secondary	Yes
DSI – Post-WWESP	No
SDA– Post-WWESP	No

A secondary WWESP or a secondary wet scrubber were eliminated from consideration because of cost-effectiveness. "Northshore estimated the annualized pollution control cost of installing and operating secondary WWESPs ranged from roughly $180,000 to $540,000 per ton of SO_2 removed. The cost of installing and operating a secondary wet scrubber was estimated to be between $140,000 and $420,000 per ton of SO_2 removed."[6] The cost-effectiveness assumed the control efficiency of a secondary WWESP to be 80 percent and the control efficiency of a secondary wet scrubber to be 60 percent.

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[5] Approval and Promulgation of Implementation Plans; States of Minnesota and Michigan; Regional Haze Federal Implementation Plan. 77 Fed. Reg. 49308. (proposed August 15, 2012), p. 49316.

[6] Ibid.

In the final Taconite FIP, EPA established an aggregate SO_2 limit of 39.0 lbs/hr on a 30-day rolling average for the furnaces when natural gas is used as fuel[7]. The BART limit is based on the WWESPs already installed on the furnaces.

SO_2 control technologies for indurating furnaces have not materially changed since the previous BART analysis. The furnaces are effectively controlled with the existing WWESPs. The cost of installing either a secondary WWESP or a secondary wet scrubber has not significantly changed since the previous BART analysis; therefore, the cost effectiveness is expected to be far too high to implement. The technical feasibility determinations of the other technologies listed above has not changed. No new SO_2 retrofit control technologies have been successfully installed on taconite indurating furnaces since the previous BART analysis.

Please contact me if you have any questions or need further information.

Sincerely,

Andrea Hayden
Environmental Manager, Northshore Mining Company

cc: Paul Carlson – Northshore
Jennifer Ramsdell – Northshore
Jason Aagenes – Cleveland-Cliffs
Teresa Kinder – Barr Engineering
Julie Miller – Barr Engineering

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[7] Approval and Promulgation of Air Quality Implementation Plans; States of Minnesota and Michigan; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze. 78 Fed. Reg. 8706. (February 6, 2013).

CLIFFS

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January 16, 2020

Mr. Steve Palzkill
Minnesota Pollution Control Agency
520 Lafayette Road N.
St. Paul, MN 55155-4194

Re: Notification of Idling of Silver Bay Power Company

Dear Mr. Palzkill,

Silver Bay Power Company (SBPC), a subsidiary of Cleveland-Cliffs Inc. (CCI), operates a power plant in Silver Bay, Minnesota to provide steam and electricity for Northshore Mining Company's (NSM) taconite processing plant. Together, the taconite processing plant and the power plant constitute one stationary source as defined in 40 CFR pt. 52 and pt. 70. The three companies together (CCI, SBPC and NSM) are considered one Permittee under Title V Permit No. 07500003-010.

SBPC consists of two Combined Heat and Power (CHP) industrial boiler generating units capable of burning solid (coal), liquid and gaseous fuels to provide process steam and electricity to NSM's taconite processing plant. Unit 1 is a Westinghouse tandem compound double flow turbine generator rated at 46 MW placed into service on October 3, 1955. Unit 2 is a Westinghouse tandem compound double flow turbine generator rated at 75 MW placed into service on January 28, 1963.

On May 23, 2016, Minnesota Power (MP), a division of Allete, Inc., and SBPC entered into a voluntary agreement with an expiration date (Agreement) that included the purchase of grid electrical power and economic idling of both CHP industrial boiler generating units. NSM has taken care to idle SPBC in an orderly manner to allow for future, potential re-activation. In fact, NSM agreed to maintain the units in a manner that allows startup if/when called upon by MP to address regional electrical grid stability requirements. Further, NSM presently intends to continue maintaining the facility for potential utilization after expiration of the Agreement. Therefore, NSM is maintaining the fully permitted, active status of SBPC's two CHP industrial boiler generating units, Unit 1 and Unit 2 (Emission Unit 001 and 002, respectively) in Title V Permit #07500003-010 and subsequent iterations of that permit. NSM also asks that MPCA continue to retain the emissions attributable to these sources in the State's emission inventory database.

In order to meet the steam demands of the taconite processing facility when SPBC is not operating, NSM invested in the permitting and construction of a steam plant consisting of three 80 MMBtu/hr natural gas fired package boilers in 2018/2019. This installation allows NSM to generate steam for slurry and space heating from the new steam plant instead of from SBPC. In parallel, MP completed necessary transmission upgrades to directly support the electrical needs of NSM's operations. Once all upgrades were completed, a phased idling of both units took place with Unit 1 (EU001) operating through June 7, 2019, and Unit 2 (EU002) through September 15, 2019.

To prevent corrosion and to minimize the possibility of fire, the power boilers, turbine generators and all associated equipment were drained as part of SBPC's standardized dry layup process. The Electric Power Research Institute document number CS-5112 (Abraham, R.S. Guidelines: *Long-term Layup of Fossil*

Plants: Final Report – 1987) has been and will continue to be followed for long-term storage and preservation of SPBC's assets.

If you have any questions regarding this notification, please contact me at (218) 226-8267 or by email at andrea.hayden@clevelandcliffs.com.

Sincerely,

Andrea Hayden, Environmental Manager
Northshore Mining Company

Cc: Paul Carlson – NSM
Jennifer Ramsdell - NSM
Scott Gischia – Cliffs
Jason Aagenes – Cliffs
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July 6, 2020

Mr. Hassan M. Bouchareb
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155-4194

Re: Response to Request for Information – Regional Haze Rule, Reasonable Progress, Four Factor Analysis for Indurating Furnaces 11 and 12 at Northshore Mining Company

Dear Mr. Bouchareb:

This letter is in response to the Minnesota Pollution Control Agency's (MPCA's) February 24, 2020 request for information (RFI) letter sent to Cleveland-Cliffs Inc. Northshore Mining Company (Northshore). The February 24, 2020 RFI stated that Northshore emission units were identified as a significant source of NO_X and SO_2 and are located close enough to Voyageurs National Park and Boundary Waters Canoe Area Wilderness to potentially cause or contribute to visibility impairment in these Class I areas. Therefore, the MPCA requested Northshore to submit a "four-factor analysis" by July 31, 2020 for the emission units identified in Table 1 for NOx and SO_2.

Table 1: Identified Emission Units

Unit	Unit ID
Indurating Furnace 11	EQUI 126 & EQUI 127/ EU100 & EU104
Indurating Furnace 12	EQUI 128 & EQUI 129 / EU110 & EU1114
Power Boiler 1	EQUI 14 / EU001
Power Boiler 2	EQUI 15 / EU002

The "four-factor analysis" is a control equipment evaluation, similar to the Best Available Control Technology (BACT) and Best Available Retrofit Technology (BART) evaluations, that must address the four statutory factors laid out in 40 CFR 51.308(f)(2)(i):

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

The MPCA intends to use the four-factor analyses to evaluate additional control measures as part of the development of the State Implementation Plan (SIP), which is due to be submitted to United States Environmental Protection Agency (USEPA) by July 31, 2021. The SIP will be prepared to address the second regional haze implementation period, which ends in 2028.

This letter considers whether a four-factor analysis is warranted for Northshore's indurating furnaces because the furnaces can be classified as an "effectively controlled" source for NO_x and SO_2. The MPCA can exclude such sources for evaluation per the regulatory requirements of the Regional Haze Rule and the United States Environmental Protection Agency (USEPA) August 20, 2019 Regional Haze Guidance Memorandum (2019 RH SIP Guidance)[1].

In Section II.B.3.f of the 2019 RH SIP Guidance[2], the USEPA acknowledges that states may forgo requiring facilities to complete the detailed four-factor analysis:

> *"It may be reasonable for a state not to select an effectively controlled source. A source may already have effective controls in place as a result of a previous regional haze SIP or to meet another CAA requirement."*[3]

The associated rationale is that:

> "*…it is reasonable to assume for the purposes of efficiency and prioritization that a full four-factor analysis would likely result in the conclusion that no further controls are necessary*"[4] to make reasonable progress towards reducing visibility impairments at Class I areas.

Section II.B.4.h. of the 2019 RH SIP Guidance[5] states,

> *"It may be appropriate for a state to rely on a previous BART analysis or reasonable progress analysis for the characterization of a factor, for example information developed in the first implementation period on the availability, cost, and effectiveness of controls for a particular source, if the previous analysis was sound and no significant new information is available."*

The 2019 RH SIP Guidance identified example scenarios and described the associated rationale for why the sources are "effectively controlled" and that states can exclude similar sources from needing to complete a four-factor analysis. The USEPA stated "*BART-eligible units that installed and began operating controls to meet BART emission limits for the first implementation period*" may be "effectively controlled"

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[1] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[2] Ibid, page 11.

[3] Ibid, page 22.

[4] Ibid, page 23.

[5] Ibid, page 28.

for the associated pollutants.[6] The USEPA notes, "*it may be unlikely that there will be further available reasonable controls for such sources.*"[7] However, the USEPA adds that, "*states may not categorically exclude all BART-eligible sources, or all sources that installed BART control, as candidates for selection for analysis of control measures.*"[8] The USEPA further notes that, "*a state might, however, have a different, reasonable basis for not selecting such sources* [sources for which existing controls were determined to be BART] *for control measure analysis.*"

As described below, Indurating Furnaces 11 and 12 meet the "effectively controlled" source example scenario for units with BART NOx and SO_2 emission limits which the USEPA concluded that states could exclude from completing a four-factor analysis.

Process Description

Indurating Furnaces 11 and 12 are straight grate furnaces in which pellets move through the entire furnace on a traveling grate. The pellet hardening and oxidation section of the indurating furnace is designed to operate at 2,400 °F. This temperature is required to meet taconite pellet product specifications. Fuel combustion in the induration furnace is carried out at 300 percent to 400 percent excess air to provide sufficient oxygen for pellet oxidation.

Air is used for combustion, pellet cooling, and as a source of oxygen for pellet oxidation. Due to the high-energy demands of the induration process, indurating furnaces have been designed to recover as much heat as possible using hot exhaust gases to heat up incoming pellets. Pellet drying and preheat zones are heated with the hot gases generated in the pellet hardening/oxidation section and the pellet cooler sections. Each of these sections is designed to maximize heat recovery within process constraints. The pellet coolers are also used to preheat combustion air so more of the fuel's energy is directed to the process instead of heating ambient air to combustion temperatures.

Indurating Furnaces 11 and 12 are permitted to burn natural gas and fuel oil. SO_2 emissions are controlled by wet walled electrostatic precipitators (WWESP) using caustic reagent to offset acid conditions.

BART-required Control Equipment Installation Scenario

Indurating Furnaces 11 and 12 were BART-eligible units and BART limits were established during the first implementation phase. The 30 day-rolling average BART limits of 1.2-1.5lb NOx/MMBtu for each furnace (fuel dependent) and 39.0 lb SO_2/hr for both furnaces combined were established in the final Federal Implementation Plan (FIP) dated February 6, 2013[9]. The BART limits from the FIP are shown in Table 2.

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[6] Ibid, page 25.

[7] Ibid.

[8] Ibid.

[9] Federal Register/ Vol. 78. No. 25, February 6, 2013, EPA-R05-OAR-2010-0037 beginning on page 8706.

Table 2 BART NOx and SO_2 Emission Limits

Unit	Unit ID	NOx Limit (lb/MMBtu)	SO_2 Limit (lb/hr)
Indurating Furnace 11	EQUI 126 & EQUI 127/ EU100 & EU104	1.2-1.5	39
Indurating Furnace 12	EQUI 128 & EQUI 129 / EU110 & EU1114		

Indurating Furnaces 11 and 12 did not require installation of additional control equipment to meet the FIP NOx limits because the furnaces design inherently results in low NOx development. The Northshore furnaces emit the lowest tons of NOx per long ton product of any taconite producer making similar pellets. Northshore's furnaces are of an early vintage, which utilizes numerous burners critically located to supply heat to the various furnace sections. The burner layout limits production capability for the size of the furnace. This furnace design is not used by any other taconite producer. An inherent design that prevents formation of the pollutants far exceeds add-on controls that could result in environmental impacts such as higher collateral carbon monoxide formation. In accordance with the FIP, Northshore has continued to operate the indurating furnaces in compliance with the FIP NOx emission limits. Thus, the indurating furnaces are considered "effectively controlled" sources in accordance with the 2019 Guidance and can reasonably be excluded from the requirement to prepare and submit a four-factor analysis for NOx.

Northshore's furnaces are only capable of burning natural gas and fuel oil; with natural gas as the primary fuel. Since natural gas is low in sulfur, the primary source of SO_2 emissions is from trace amounts of sulfur in the iron concentrate and binding agents. Sulfur is also present in fuel oil, if used. Both lines are controlled by WWESPs using caustic reagent. Stack testing using natural gas fuel has demonstrated the WWESP effectively removes SO_2 to one to two parts per million in the exhaust. The USEPA concluded in the 2013 FIP.[10] that because Northshore is burning natural gas and fuel oil, additional SO_2 controls are not economically reasonable and are therefore, not necessary for BART. In accordance with the FIP, Northshore has continued to operate the BART SO_2 control measures and is complying with the FIP SO_2 emission limits. Thus, the indurating furnaces are considered "effectively controlled" sources in accordance with the 2019 RH SIP Guidance and can reasonably be excluded from the requirement to prepare and submit a four-factor analysis for SO_2.

The indurating furnaces meet the USEPA's scenario for effectively controlled units because:

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[10] Approval and Promulgation of Air Quality Implementation Plans; States of Minnesota and Michigan; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze; Final Rule. 78 Fed. Reg. 8706 (February 6, 2013)

- The indurating furnaces are BART-eligible units, as determined by Minnesota's December 2009 Regional Haze Plan, and are regulated under 40 CFR 52.1235 (Approval and Promulgation of Implementation Plans – Subpart Y Minnesota – Regional Haze)
- The indurating furnaces have controls and must "meet BART emission limits for the first implementation period" for NOx and SO_2
- In 2013, EPA promulgated a FIP that included, among other things, BART requirements to effectively control NOx and SO_2 for the Northshore indurating furnaces.
- No significant new control technology is available for indurating furnaces since the previous BART analysis.

Northshore is requesting that Indurating Furnaces 11 and 12 be excluded from the request to prepare a four-factor analysis. We are confident a full four-factor analysis would result in the conclusion that no further controls are necessary for the furnaces. Northshore will complete a Four Factor Analysis for Power Boilers 1 and 2 by July 31, 2020. Because of MPCA's request for completion of the Four Factor Analysis by July 31, 2020, Northshore is requesting a response from MPCA as soon as possible regarding this request. Thank you for your consideration.

Sincerely,

Andrea Hayden
Environmental Manager, Northshore Mining Company

cc: Paul Carlson – Northshore
Jennifer Ramsdell – Northshore
Jason Aagenes – Cleveland-Cliffs
Teresa Kinder – Barr Engineering
Julie Miller – Barr Engineering

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July 30, 2020

Mr. Hassan M. Bouchareb
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155-4194

Re: Follow Up to Response to Request for Information – Regional Haze Rule, Reasonable Progress, Four Factor Analysis for Indurating Furnaces 11 and 12 at Northshore Mining Company

Dear Mr. Bouchareb:

This letter is in response to the Minnesota Pollution Control Agency's (MPCA) email to Northshore Mining Company (Northshore) dated July 28, 2020 regarding the determination on whether Indurating Furnaces 11 and 12 can be considered effectively controlled. MPCA's email reads as follows:

Please provide a short overview of the different emission reduction opportunities evaluated at part of the Taconite FIP for Northshore. I'm specifically looking for:

- *Each reduction measure that was evaluated for NOX/SO2 control within the FIP;*
- *Whether the measure was eliminated from consideration based on technical feasibility;*
- *Whether the measure was eliminated from consideration based on cost-effectiveness; and*
- *Whether or not these determinations have materially changed since they were completed.*

Background

On August 15, 2012, the Environmental Protection Agency (EPA) proposed the Regional Haze Federal Implementation Plan (FIP) to address best available retrofit technology (BART) for taconite plants in Minnesota and Michigan.[1] The proposed FIP contained a BART analysis for Northshore's Indurating Furnaces 11 and 12. EPA's FIP was informed by Northshore's submittal to the MPCA on September 6, 2006, "Northshore Mining Company Analysis of Best Available Retrofit Technology (BART)" [2006 BART Analysis][2]. The information used for the Taconite FIP is summarized in the following paragraphs.

NOx BART Analysis

The following NOx retrofit control technologies were identified for indurating furnaces in the FIP:

- External Flue Gas Recirculation,
- Low-NOx Burners,
- Induced Flue Gas Recirculation Burners,

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[1] Approval and Promulgation of Implementation Plans; States of Minnesota and Michigan; Regional Haze Federal Implementation Plan. 77 Fed. Reg. 49308. (proposed August 15, 2012).

[2] https://www.pca.state.mn.us/sites/default/files/bart-facility-northshore.pdf

- Energy Efficiency Projects,
- Ported Kilns,
- Alternate Fuels, and
- Selective Catalytic Reduction (SCR).

Table 1 summarizes the technologies that were eliminated from consideration based on technical feasibility.

Table 1 Potential NOx Emission Control Measures Technical Feasibility Conclusions[3]

NO_X Control Measure	Technically Feasible for Straight Grate Furnace?
Pre-Combustion, Combustion, or Operational Controls	
LNB	No – Already required under FIP
EFGR	No
IFGR	No
Ported Kilns	No
Energy Efficiency Projects	No
Alternate Fuels	No
Post-Combustion Controls	
SCR – Pre-WWESP	No
SCR – Post-WWESP with Conventional Duct Burner Reheat	Potentially

In the proposed FIP, EPA states that U.S. Steel documented the infeasibility of SCR controls. In its 2006 BART Analysis, Northshore identified SCR with conventional reheat as potentially technically feasible. SCR with conventional reheat was eliminated from consideration based on cost-effectiveness in the 2006 BART Analysis. The annualized control cost was expected to be over $200,000 per ton for each furnace.

In the final FIP dated February 6, 2013, EPA established a NOx limit of 1.2 lbs/MMBtu on a 30-day rolling average for the furnaces when natural gas is used as fuel.[4] The BART limit is based on the expected control achieved using low NOx burners. However, as described in the letter to MPCA dated July 6, 2020, Indurating Furnaces 11 and 12 did not require actual installation of low NOx burners to meet BART NOx limits because the furnaces design inherently results in low NOx development.

NOx control technologies for indurating furnaces have not materially changed since the previous BART analysis. The furnaces are effectively controlled to the same level as low NOx burners. The furnaces' designs would not allow for changes in burner technology that would further reduce NOx emissions. The cost of SCR with conventional reheat has not significantly changed since the previous BART analysis; therefore, the cost effectiveness is expected to be far too high to implement SCR technology. The

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[3] Ibid., 49315.

[4] Approval and Promulgation of Air Quality Implementation Plans; States of Minnesota and Michigan; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze. 78 Fed. Reg. 8706. (February 6, 2013).

technical feasibility determinations of the other technologies listed above has not changed. No new NOx retrofit control technologies have been successfully installed on taconite indurating furnaces since the previous BART analysis.

SO_2 BART Analysis

Both furnaces are controlled by wet-walled electrostatic precipitators (WWESP) using caustic reagent. The following SO_2 retrofit control technologies were identified for indurating furnaces in the FIP:

- Wet-Walled Electrostatic Precipitator,
- Wet Scrubbing,
- Dry Sorbent Injection (DSI),
- Spray Dryer Absorption (SDA),
- Energy Efficiency Projects,
- Alternate Fuels, and
- Coal Drying.

Table 2 summarizes the technologies that were eliminated from consideration based on technical feasibility.

Table 2 Potential SO_2 Emission Control Measures Technical Feasibility Conclusions[5]

SO_2 Control Measure	Technically Feasible for Straight Grate Furnace?
Pre-Combustion, Combustion, or Operational Controls	
Energy Efficiency Projects	No
Alternate Fuels	No
Coal Drying	No
Post-Combustion Controls	
WWESP - Secondary	Yes
Wet Scrubbing – Secondary	Yes
DSI – Post-WWESP	No
SDA– Post-WWESP	No

A secondary WWESP or a secondary wet scrubber were eliminated from consideration because of cost-effectiveness. “Northshore estimated the annualized pollution control cost of installing and operating secondary WWESPs ranged from roughly $180,000 to $540,000 per ton of SO_2 removed. The cost of installing and operating a secondary wet scrubber was estimated to be between $140,000 and $420,000 per ton of SO_2 removed.”[6] The cost-effectiveness assumed the control efficiency of a secondary WWESP to be 80 percent and the control efficiency of a secondary wet scrubber to be 60 percent.

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[5] Approval and Promulgation of Implementation Plans; States of Minnesota and Michigan; Regional Haze Federal Implementation Plan. 77 Fed. Reg. 49308. (proposed August 15, 2012), p. 49316.

[6] Ibid.

In the final Taconite FIP, EPA established an aggregate SO_2 limit of 39.0 lbs/hr on a 30-day rolling average for the furnaces when natural gas is used as fuel[7]. The BART limit is based on the WWESPs already installed on the furnaces.

SO_2 control technologies for indurating furnaces have not materially changed since the previous BART analysis. The furnaces are effectively controlled with the existing WWESPs. The cost of installing either a secondary WWESP or a secondary wet scrubber has not significantly changed since the previous BART analysis; therefore, the cost effectiveness is expected to be far too high to implement. The technical feasibility determinations of the other technologies listed above has not changed. No new SO_2 retrofit control technologies have been successfully installed on taconite indurating furnaces since the previous BART analysis.

Please contact me if you have any questions or need further information.

Sincerely,

Andrea Hayden
Environmental Manager, Northshore Mining Company

cc: Paul Carlson – Northshore
Jennifer Ramsdell – Northshore
Jason Aagenes – Cleveland-Cliffs
Teresa Kinder – Barr Engineering
Julie Miller – Barr Engineering

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[7] Approval and Promulgation of Air Quality Implementation Plans; States of Minnesota and Michigan; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze. 78 Fed. Reg. 8706. (February 6, 2013).

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CONTROL AGENCY

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January 29, 2020

Robert Schilling, Manager
Sappi Cloquet LLC
2201 Avenue B
Cloquet, MN 55720

RE: Request for Information - Regional Haze Rule, Reasonable Progress, Four Factor Analysis

Dear Mr. Schilling:

The Minnesota Pollution Control Agency (MPCA) is currently preparing information for the second planning period (Round 2) comprehensive update to Minnesota's Regional Haze State Implementation Plan (SIP) as required by the Regional Haze Rule (40 CFR § 51.308). States are responsible for developing a Regional Haze SIP that addresses regional haze in each Class I area located within the state and in each Class I area located outside the state which may be affected by emissions from sources within the state. The Regional Haze SIP is required to identify existing facilities that cause or contribute to visibility impairment; analyze, identify, and apply federally-enforceable control strategies for those sources; and periodically demonstrate reasonable progress toward reaching visibility goals. States are also responsible for periodic comprehensive updates to their Regional Haze SIP that address these same topics. Minnesota's Round 2 Regional Haze SIP must be submitted to the U.S. Environmental Protection Agency (U.S. EPA) by July 31, 2021.

Minnesota has two Class I areas within its borders, the Boundary Waters Canoe Area Wilderness (BWCA) and Voyageurs National Park (Voyageurs). Other nearby Class I areas include Isle Royale National Park in Michigan. Therefore, Minnesota must prepare a Regional Haze SIP that identifies sources that cause or contribute to visibility impairment in these areas. To meet the core requirements for regional haze for these areas, Minnesota must submit a SIP that contains the plan elements and supporting documentation for all required analyses identified in 40 CFR § 51.308(f).

In the first planning period (Round 1), the focus of the Regional Haze Rule was on establishing Best Available Retrofit Technology (BART) for certain older sources and reasonable progress towards national visibility goals. In Round 2, there are no BART requirements; therefore, the focus is on making reasonable progress. The U.S. Environmental Protection agency has defined the methodology that states must use to determine what measures are necessary to make reasonable progress in 40 CFR § 51.308(f)(2). At minimum, the reasonable progress analysis must use the four factors identified in 40 CFR § 51.308(f)(2)(i) to evaluate and determine the emission reduction measures necessary to make reasonable progress. The four factors are:

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

Data from the IMPROVE monitoring sites at BWCA and Voyageurs indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X).

You are receiving this letter because your facility was identified as a significant source of NO_X and SO_2 and is located close enough to the BWCA or Voyageurs to potentially cause or contribute to visibility impairment in these Class I areas. Therefore, the MPCA requests that you prepare a "Four Factor Analysis" for the following emission units:

1. Power Boiler #9 (EQUI 4 / EU 004) that addresses emissions of NO_X and SO_2
2. Recovery Boiler #10 (EQUI 53 / EU 005) that addresses emissions of NO_X

The analysis should be prepared using the U.S. Environmental Protection Agency guidance[1] that provides recommendations for how each of the factors should be determined.

Preparation of the comprehensive update to Minnesota's Regional Haze SIP will require extensive planning and review of sources in Minnesota. The MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to prepare the Regional Haze SIP. The MPCA expects air quality modeling of potential regional emissions reductions will be conducted beginning in spring 2020. I appreciate your attention to this matter and request that you **submit the Four Factor Analysis by July 31, 2020**.

If you have any questions regarding this matter, or would like to request a meeting to further discuss the contents of this letter, please contact me by phone at 651-757-2653 or by email at Hassan.Bouchareb@state.mn.us.

Sincerely,

Hassan Bouchareb

This document has been electronically signed.

Hassan M. Bouchareb
Engineer
Environmental Analysis and Outcomes Division

Cc: Michael Schultz, Sappi Cloquet LLC
Deepa de Alwis, MPCA
Cory Boeck, MPCA
Frank Kohlasch, MPCA
Agency Interest ID 2309

Address questions and submittals requested above to:

Hassan M. Bouchareb
Minnesota Pollution Control Agency
520 Lafayette Road North
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(651) 757-2653
Hassan.Bouchareb@state.mn.us

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[1] **U.S. Environmental Protection Agency.** *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 20, 2019, https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

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Mr Hassan Bouchareb
Environmental and Outcomes Division
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155-4194
UNITED STATES OF AMERICA

22 July 2020

Dear Mr. Bouchareb

Request for Information – Regional Haze Rule Four-Factor Analysis for NOx and SO_2 Emissions Control

Sappi Cloquet LLC submits the attached Four-Factor Analysis for NOx and SO_2 Emissions Control for Power Boiler #9 (EQUI 4) and Recovery Boiler #10 (EQUI 53) to satisfy the request for information sent on January 29, 2020. Barr Engineering prepared the four-factor analysis for Sappi Cloquet LLC. The report concludes existing permit controls and limits effectively control NOx and SO_2 emissions from Power Boiler #9 and NOx emissions from Recovery Boiler #10. In addition, the report concludes MPCA should use the current trend of emissions reductions to demonstrate reasonable progress toward reducing visibility impairment.

The Recovery Boiler #10 underwent a BACT review for NOx, among other pollutants, and the associated construction permit was issued in 2017 (Air Permit 01700002-101) which is after the USEPA's July 31, 2013 scenario threshold date and qualifies it as being "effectively controlled."

Power Boiler #9 underwent a four-factor analysis. The result of which is that the installation of additional control equipment for NO2 and SO2 is not justified based on the cost of compliance as seen in the table below.

Additional Emissions Control Measure	**Factor 1 – Cost of Compliance**
SCR	$9,493/ton
SNCR	$7,191/ton

As for the fifth factor, a visibility impacts review was conducted that shows visibility improvements are unlikely with the addition of either of these emissions control measures.

This Four-Factor Analysis is being submitted to Hassan Bouchareb by certified mail and electronically at Hassan.Bouchareb@state.mn.us .

Please contact Alycia McWilliams at 218-879-0637 if you have any questions or comments concerning this report.

Yours sincerely

Tom Radovich
Managing Director
Cloquet Operations

sappi/999

Regional Haze Four-Factor Analysis for NO_X and SO_2 Emissions Control

Power Boiler #9 (EQUI 4 / EU 004)
Recovery Boiler #10 (EQUI 53 / EU 005)

Prepared for
Sappi Cloquet LLC

July 17, 2020

Regional Haze Four-Factor Analysis for NO_X and SO_2 Emissions Control

Power Boiler #9 (EQUI 4 / EU 004)
Recovery Boiler #10 (EQUI 53 / EU 005)

Prepared for
Sappi Cloquet LLC

July 17, 2020

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Regional Haze Four-Factor Analysis for NO_X and SO_2 Emissions Control

July 17, 2020

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1 Executive Summary

This report presents Sappi Cloquet LLC (Sappi's) response to the Minnesota Pollution Control Agency's (MPCA's) January 29, 2020 Request for Information (RFI) Letter[1] regarding the Regional Haze Rule (RHR)[2] and the state's requirement to make reasonable progress on visibility improvement at nearby Class I areas.[3] As required by the RFI, the report presents the emissions reduction evaluation for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) from Power Boiler #9 (EQUI 4 / EU 004) and for NO_X from Recovery Boiler #10 (EQUI 53 / EU 005). The report was prepared following the requirements of the RHR (40 CFR 51.308) and is consistent with the final U.S. Environmental Protection Agency (EPA) RHR State Implementation Plan (SIP) guidance[4] (2019 SIP Guidance).

Evaluation for Power Boiler #9: The analysis for Power Boiler #9 considers potential emissions reduction measures for NO_X (Section 3.1) and SO_2 (Section 3.2) by addressing the four statutory factors laid out in 40 CFR 51.308(f)(2)(i):

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

The analyses are summarized in Table 1-2 and Table 1-3 for NO_X and SO_2, respectively. These analyses demonstrate that the installation of additional control equipment NO_X and SO_2 is not justified based on the four statutory factors.

In addition, Section 5.1 provides visibility monitoring data that demonstrates that the current visibility impairment in the nearby Class I areas is already below the 2028 Uniform Rate of Progress (URP), suggesting that the MPCA should use the current trend of emission reductions to demonstrate reasonable progress. Furthermore, Section 5.2 provides results from a particle trajectory analyses for the most

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[1] January 29, 2020 letter from Hassan Bouchareb of MPCA to Sappi

[2] The regional haze program requirements are promulgated at 40 CFR 51.308. The SIP requirements for this implementation period are specified in §51.308(f).

[3] MPCA's letter identified the Boundary Waters Canoe Area Wilderness (Boundary Waters), Voyageurs National Park (Voyageurs) and Isle Royale National Park (Isle Royale) as the nearby Class I areas

[4] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003.

impaired days at the Boundary Waters visibility monitor and concludes that additional control measures implemented at Sappi are unlikely to provide a substantial improvement in visibility in the Class I areas.

This analysis does not support the installation of additional NO_X or SO_2 emission control measures at Power Boiler #9 beyond those described in Section 2.3. As such, Sappi proposes to maintain the existing NO_X or SO_2 permit limits presented in Table 2-2.

Evaluation for Recovery Boiler #10: The 2019 SIP Guidance states that it “may be reasonable for a state not to select an effectively controlled source”[5] for the four-factor analysis with the rationale that “it is reasonable to assume for the purposes of efficiency and prioritization that a full four-factor analysis would likely result in the conclusion that no further controls necessary.”[6] Section 4 demonstrates that Recovery Boiler #10 is “effectively controlled” and, therefore, a four-factor analysis was not completed for this source.

This analysis does not support the installation of additional NO_X emissions measures at Recovery Boiler #10 beyond those described in Section 2.3. As such, Sappi proposes to maintain the existing NO_X permit limits presented in Table 2-3.

Update to Baseline Emission Rates: The 2019 SIP Guidance states that the “projected 2028 (or the current) scenario can be a reasonable and convenient choice for use as the baseline control scenario for measuring the incremental effects of potential reasonable progress control measures on emissions, costs, visibility, and other factors.”[7] Sappi anticipates flat growth in the paper industry and projects that emissions in 2028 will be equivalent to 2019 actual emissions.

The MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to evaluate regional emission reductions. Sappi proposed to revise the projected emissions for LADCO’s evaluation as shown in Table 3-2.

Table 1-1: Projected 2028 NO_X Emissions (tons per year)

Year	Source	Pollutant	Annual Emissions
2019 Actual Emissions And 2028 Projected Emissions	Power Boiler #9	NO_X	347 tons/year
	Power Boiler #9	SO_2	22 tons/year
	Recovery Boiler #10	NO_X	680 tons/year

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[5] Ibid, Page 22.

[6] Ibid, Page 23.

[7] Ibid, page 29.

Table 1-2: Summary of NO_X Four-factor Analysis

Emission Reduction Technology	Factor 1 Cost of Compliance	Factor 2 Time Necessary for Compliance	Factor 3 Energy and Non Air Quality Environmental Impacts of Compliance	Factor 4 Remaining Useful Life of the Source	Factor 5 Visibility Improvements	Does this Analysis Support the Installation of this Emission Reduction Technology?
SCR	$9,493/ton	3 years after SIP approval	• Catalyst plugging could lead to decreased control efficiency, decreased catalyst life, and additional boiler downtime • Increased truck and/or train traffic (reagent and catalyst deliveries) • Possible ammonia slip (unreacted reagent that is emitted to the atmosphere) • Increased natural gas burning to reheat flue gas to achieve SCR inlet temperatures • Catalyst regeneration • Catalyst disposal • Electricity consumption (fans and pumps)	No shutdown or rebuild of Power Boiler #9 is anticipated	Unlikely	No
SNCR	$7,191/ton	3 years after SIP approval	• Increased truck and/or train traffic (reagent deliveries) • Possible ammonia slip (unreacted reagent that is emitted to the atmosphere) • Nitrous oxide (N2O) generation (a greenhouse gas) • Electricity consumption (fans and pumps)	No shutdown or rebuild of Power Boiler #9 is anticipated	Unlikely	No

Table 1-3: Summary of SO_2 Four-factor Analysis

List of Emission Reduction Technology	Factor 1 Cost of Compliance	Factor 2 Time Necessary for Compliance	Factor 3 Energy and Non Air Quality Environmental Impacts of Compliance	Factor 4 Remaining Useful Life of the Source	Factor 5 Visibility Improvements	Does this Analysis Support the Installation of this Emission Reduction Technology?
Spray dryer	$1,589,900	3 years after SIP approval	• Increased waste generation and disposal due to additional material collected in the particulate emissions control system • Increased truck and/or train traffic (reagent deliveries and waste hauling) • Water consumption for slurry • Electricity consumption (fans and pumps) • Wastewater generation and disposal	No shutdown or rebuild of Power Boiler #9 is anticipated	Unlikely	No
Dry sorbent injection	$5,672,396	3 years after SIP approval	• Increased waste generation and disposal due to additional material collected in the particulate emissions control system • Increased truck and/or train traffic (reagent deliveries and waste hauling) • Electricity consumption (fans and pumps)	No shutdown or rebuild of Power Boiler #9 is anticipated	Unlikely	No

2 Introduction

This section discussed the pertinent regulatory background information, and a description of Sappi's boilers.

2.1 Four-factor Analysis Regulatory Background

The RHR defines regional haze as "visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area." Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources. The RHR requires state regulatory agencies to submit a series of SIPs in ten-year increments to protect visibility in certain national parks and wilderness areas, known as mandatory Class I areas. The original RHR SIPs were due in 2007 and included milestones for establishing reasonable progress towards the visibility improvement goals, with the ultimate goal to achieve natural background visibility by 2064. The SIP for the first RHR planning period was informed by best available retrofit technology (BART) analyses that were completed on all subject-to-BART sources. The second RHR planning period requires development and submittal of updated SIPs by July 31, 2021.

On January 29, 2020, the MPCA sent an RFI to Sappi. The RFI stated that data from the Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring sites at Boundary Waters Canoe Area Wilderness (Boundary Waters) and Voyageurs National Park (Voyageurs) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of SO_2 and NO_X. In addition, emissions from sources in Minnesota could potentially impact Class I areas in nearby states, namely Isle Royale National Park (Isle Royale) in Michigan. Although Michigan is responsible for evaluating haze in Isle Royale, Michigan must consult with surrounding states, including Minnesota, on potential cross-state haze pollution impacts. As part of the planning process for the SIP development, MPCA is working with the LADCO to evaluate regional emission reductions.

In addition, the RFI stated that the facility was identified as a significant source of NO_X and SO_2 that is located close enough to the Boundary Waters and Voyageurs to potentially cause or contribute to visibility impairment. Therefore, as part of the State's development of the updated SIP, the MPCA requested that Sappi submit a "four factors analysis" (herein termed as a four-factor analysis) by July 31, 2020 for the emission units identified in Table 2-1.

Table 2-1: Identified Emission Units

Unit	Unit ID	Applicable Pollutants
Recovery Boiler #10	EQUI 53 / EU 005	NO_X
Power Boiler #9	EQUI 4 / EU 004	NO_X, SO_2

The analysis must consider potential emissions reduction measures by addressing the four statutory factors which are laid out in 40 CFR 51.308(f)(2)(i):

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

The RFI letter to Sappi specified that the "… analysis should be prepared using the U.S. Environmental Protection Agency guidance" referring to the final 2019 SIP Guidance.

This report describes the background and analysis for conducting a four-factor analysis for NO_X and SO_2 as applied to the review of emissions controls at Sappi for the units identified in Table 2-1.

2.2 Description of Affected Emission Units

Sappi is an existing pulp and paper mill which manufactures kraft paper pulp, dissolving wood pulp, and fine coated paper. The two emissions units included in MPCA's RFI are:

- **Power Boiler #9:** This emission unit is a stoker grate design boiler which produce steam to generate electricity and provide heat for other processes at the plant. The boiler burns primarily hog fuel (biomass which is primarily bark from the facility de-barking process), utilizes natural gas as a startup/supplemental fuel and is permitted to burn distillate oil which is maintained as a backup fuel source. The boiler is also a backup combustion source for non-condensable gases (NCG) which are the exhaust gases from the digestion and BLS evaporation processes. Particulate matter emissions from the power boiler are controlled by multiclones and a high-efficiency electrostatic precipitator (ESP).

- **Recovery Boiler #10:** This emission unit burns strong black liquor solids (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 boiler where the organic portion of the BLS is burned to produce steam to generate electricity and provide heat for other processes at the plant. The cooking chemicals collect as molten smelt at the bottom of the boiler. The recovery boiler is a primary source of all criteria pollutant emissions, as well as sulfuric acid (H_2SO_4), total reduced sulfur (TRS), and Hazardous Air Pollutants (HAP). Particulate matter emissions from the recovery boiler are controlled by a high-efficiency ESP.

2.3 Existing Emission Controls and Limits

The NO_X and SO_2 limits for Power Boiler #9 from Air Permit 01700002-103 are presented in Table 2-2. Power Boiler #9 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.

Table 2-2: Power Boiler #9 – NO_X and SO_2 Permit Limits

Pollutant	Condition	Limit	Basis of Limit
NO_X	5.9.8	Nitrogen Dioxide <= 151.10 pounds per hour 30-day rolling average.	Prevention of Significant Deterioration (PSD) modeling
NO_X	5.9.9	Nitrogen Dioxide <= 0.20 to 0.70 pounds per million Btu heat input 3-hour rolling average. [Based on fuel mix]	New Source Performance Standards (NSPS) Subpart D
NO_X	5.9.10	Nitrogen Oxides <= 200.0 pounds per hour.	PSD modeling
SO_2	5.9.11	Sulfur Dioxide <= 24.60 pounds per hour. This limit does not apply when boiler is used as back-up incineration for NCG.	PSD modeling
SO_2	5.9.12	Sulfur Dioxide <= 0.80 pounds per million Btu heat input 3-hour rolling average while burning fuel oil or fuel oil and wood. While burning coal, wood, or coal and wood, SO_2 must be less than or equal to 1.2 lb/mmBtu. These limits also apply if natural gas is being burned in combination with these fuels. [Formula for other fuel mixes] All emission limits shall be determined on a 3-hour rolling average basis. NCG is not considered a fuel, and the contribution from burning NCGs is to be disregarded when determining compliance with this limit.	NSPS Subpart D

The NO_X limits for Recovery Boiler #10 from Air Permit 01700002-103 are presented in Table 2-3. Recovery Boiler #10 does not have add-on NO_X controls but does use quaternary air injection to manage the generation of NO_X.

Table 2-3: Recovery Boiler #10 – NO_X Permit Limits

Pollutant	Condition	Limit	Basis of Limit
NO_X	5.17.11	Nitrogen Dioxide <= 100 parts per million 30-day rolling average by volume (dry) corrected to 8% oxygen.	BACT limit
NO_X	5.17.12	Nitrogen Dioxide <= 226.5 pounds per hour 30-day rolling average.	MPCA limit
NO_X	5.17.13	Nitrogen Dioxide <= 241.0 pounds per hour 30-day rolling average.	PSD modeling
NO_X	5.17.14	Nitrogen Oxides <= 241.0 pounds per hour 1-hour average.	BACT limit
NO_X	5.17.15	Nitrogen Dioxide <= 0.20 pounds per million Btu heat input 30-day rolling average while burning natural gas only or fuel oil combined with black liquor.	NSPS Subpart Db

3 Power Boiler #9: Four-factor Analysis

3.1 NO_X Four-factor Analysis – Power Boiler #9

This section identifies baseline emission rates and evaluates the four statutory factors for NO_X emissions from Power Boiler #9.

3.1.1 Emission Control Options

The 2019 SIP Guidance states that the "first step in characterizing control measures for a source is the identification of technically feasible control measures for those pollutants that contribute to visibility impairment."[8] However, USEPA recognized that a "state must reasonably pick and justify the measures that it will consider, recognizing that there is no statutory or regulatory requirement to consider all technically feasible measures or any particular measures."[9] This section addresses the selection of emission control options for NO_X from Power Boiler #9.

The following methodology was used to determine which emission control technologies should be considered in the four factor analysis:

1. Search the RACT/BACT/LAER Clearinghouse (RBLC)[10] for available control technologies with the following search criteria:
   - Similar emission unit type (process name)
   - Similar fuel
   - 10-year look back
2. Eliminate technologies that would not would not apply to the specific emission unit under consideration (example: eliminate controls for natural gas combustion when biomass is the primary fuel)
3. Advance the remaining technologies for consideration in the four factor analysis

The RBLC search for biomass power boilers for NO_X is presented in Appendix A and a summary is provided in Table 3-1.

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[8] Ibid, page 28.

[9] Ibid, Page 29.

[10] RACT/BACT/LAER Clearinghouse (RBLC) as maintained by USEPA (link to RBLC website)

Table 3-1: Biomass Power Boiler RBLC Summary – NO_X

RBLC ID	Technology
CT-0156	Regenerative SCR (RSCR)
AR-0161 KS-0034	Selective Catalytic Reduction (SCR)
CA-1203 CA-1225 GA-0141 ME-0037	Selective Non-Catalytic Reduction (SNCR)
AL-0250	Low NO_X burners

RSCR has a higher capital cost but greater energy efficiency than SCR. The control efficiencies of the two technologies are similar. RSCR is typically targeted for installation on sources with relatively low flue gas temperatures. Because flue gas temperature in Power Boiler #9 (413°F) is higher than the flue gas temperature in typical RSCR installations, the technology was not considered in the four-factor analysis.

Power Boiler #9 burns primarily hog fuel (biomass), utilizes natural gas as a startup/supplemental fuel, is a backup combustion source for NCG, and is permitted to burn distillate oil. Power Boiler #9 is a stoker grate design. Based on the primary fuel use and the design of Power Boiler #9, low NO_X burners were not considered in the four factor analysis because:

- Low NO_X burners 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.
- Low NO_X burners 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 low NO_X burners 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
- SNCR

3.1.2 Baseline Emission Rates

The 2019 SIP Guidance states that the "projected 2028 (or the current) scenario can be a reasonable and convenient choice for use as the baseline control scenario for measuring the incremental effects of potential reasonable progress control measures on emissions, costs, visibility, and other factors."[11] Thus, Sappi anticipates flat growth in the paper industry and projects that emissions in 2028 will be equivalent to 2019 actual emissions. LADCO estimated 473.87 tpy for NO_X 2028 emissions, but Sappi proposes to revise the projected emissions as shown in Table 3-2.

Table 3-2: Projected 2028 NO_X Emissions (tons per year)

Year	Power Boiler #9
2019 Actual Emissions And 2028 Projected Emissions	347 tons/year

3.1.3 Factor 1 – Cost of Compliance

Sappi has completed compliance cost estimates for the selected NO_X emission control measures following EPA's Control Cost Manual as recommended in the 2019 SIP Guidance.[12] The capital cost estimates were confirmed by Sappi's plant engineering staff as reasonable, based on their considerable experience with projects at Sappi and their informal conversations with other companies that have completed similar types of projects at other facilities. A more detailed cost estimate is likely to increase the costs for installing and implementing either of the projects. Cost calculation spreadsheets for the NO_X emission control measures are provided in Appendix B.

The cost effectiveness analysis compares the annualized cost of the technology 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.

The resulting cost effectiveness calculations are summarized in Table 3-3.

Table 3-3: Power Boiler #9 NO_X Control Cost Summary, per Unit Basis

Additional Emissions Control Measure	Total Capital Investment ($)	Total Annualized Costs ($/year)	Control Efficiency (%)	Annual Emissions Reduction (tpy)	Pollution Control Cost Effectiveness ($/ton)
SCR	$29,195,285	$2,640,036	80%	278.1 tpy	$9,493/ton
SNCR	$5,021,391	$623,834	25%	96.8 tpy	$7,191/ton

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[11] Ibid, page 29.

[12] Ibid, Page 21.

Based on the information provided in Table 3-3 and in consideration of RHR analyses conducted in other states, the emission control measures were not considered cost effective.

Sections 3.1.4 through 3.1.6 provide a screening-level summary of the remaining three factors evaluated for the NO_X emission control measures, understanding that these projects represent substantial capital investments that are not justified on a cost per ton or absolute cost basis.

3.1.4 Factor 2 – Time Necessary for Compliance

Factor #2 estimates the amount of time needed for full implementation of the different control measures. Typically, the time for compliance considers the time needed to develop and approve the new emissions limit into the SIP by state and federal action, then to implement the project necessary to meet the SIP limit via installation and tie-in of equipment for the emissions control measure.

The technologies would require significant resources and time of at least two to three years design, engineer, procure, and install the equipment. The facility would attempt to complete the construction during a regularly scheduled outage but recognizes that the outage may need to be extended to install all required equipment.

The SIP is scheduled to be submitted in 2021 with the anticipated approval in 2022 (approximately one year after submittal). Once the SIP is approved, the design, engineer, procurement and installation schedule would begin. This would put the anticipated date of installation in 2024 or 2025.

3.1.5 Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance

The energy and non-air environmental impacts associated with implementation of the above identified NO_X control measures are summarized below.

- SCR
    - Catalyst plugging could lead to decreased control efficiency, decreased catalyst life, and additional boiler downtime
    - Increased truck and/or train traffic (reagent and catalyst deliveries)
    - Possible ammonia slip (unreacted reagent that is emitted to the atmosphere)
    - Increased natural gas burning to reheat flue gas to achieve SCR inlet temperatures
    - Catalyst regeneration
    - Catalyst disposal
    - Electricity consumption (fans and pumps)

- SNCR
    - Increased truck and/or train traffic (reagent deliveries)
    - Possible ammonia slip (unreacted reagent that is emitted to the atmosphere)
    - Nitrous oxide (N_2O) generation (a greenhouse gas)
    - Electricity consumption (pumps)

3.1.6 Factor 4 – Remaining Useful Life of the Source

Because Power Boiler #9 is expected to continue operations for the foreseeable future, the useful life of the individual control measures (assumed 20-year life) was used to calculate emission reductions, amortized costs, and cost effectiveness on a dollar per ton basis.

3.1.7 Proposed NO_X Controls and Emissions Rates

This analysis does not support the installation of additional NO_X emission control measures at Power Boiler #9 beyond those described in Section 2.3. As such, Sappi proposes to maintain the existing NO_X permit limits presented in Table 2-3

3.2 SO_2 Four-factor Analysis – Power Boiler #9

This section identifies baseline emission rates and evaluates the four statutory factors for SO_2 emissions from Power Boiler #9.

3.2.1 Emission Control Options

The selection of SO_2 emission control options followed the same methodology as described in Section 3.1.1.

The RBLC search for biomass power boilers for SO_2 is presented in Appendix C and a summary is provided in Table 3-4.

Table 3-4: Biomass Power Boiler RBLC Summary – SO_2

RBLC ID	Technology
CT-0162	Spray Dryer
AR-0161 GA-0141 KS-0034	Dry Sorbent Injection
CT-0156 LA-0249 ME-0037	Low Sulfur Fuels

Low sulfur fuels were not considered in the four-factor analysis because:

- The primary fuel in Power Boiler #9 is hog fuel (biomass which is primarily bark from the facility de-barking process) which is inherently low in sulfur
- Natural gas is a supplemental fuel and is also a low sulfur fuel
- Distillate oil is an available fuel for Power Boiler #9 and the permit already includes a sulfur limit (0.050% by weight) and 12-month usage limit; distillate oil is an emergency backup fuel and is not a primary fuel for this boiler

- NCG is the primary source of SO_2 in Power Boiler #9, but the sulfur content of NCG is determined by the pulping process and it would be unreasonable to consider a change as the NCG is fundamental to the operation and design of the pulp mill; furthermore, the boiler is not the primary source for NCG combustion and the ability to combust NCG in the boiler must be maintained as part of the overall strategy for limiting emissions of HAP as required by 40 CFR Part 63 Subpart S (National Emission Standards for Hazardous Air Pollutants from the Pulp and Paper Industry)

Based on this information, the technologies that were considered in the four-factor analysis are:

- Spray dryer absorption
- Dry sorbent injection

3.2.2 Baseline Emission Rates

As described in Section 3.1.2, Sappi used projected 2028 emissions as the baseline scenario.

Sappi anticipates flat growth in the paper industry and projects SO_2 emissions in 2028 will equal 2019 actual emissions. LADCO estimated 54.18 tpy for 2028 SO_2 emissions, but Sappi proposes to revise the projected emissions as shown in Table 3-5.

Table 3-5: Projected 2028 SO_2 Emissions (tons per year)

Year	Power Boiler #9
2019 Actual Emissions And 2028 Projected Emissions	22 tons/year

3.2.3 Factor 1 – Cost of Compliance

Sappi has completed compliance cost estimates for the selected SO_2 emission control measures following EPA's Control Cost Manual as recommended in the 2019 SIP Guidance.[13] The capital cost estimates were confirmed by Sappi's plant engineering staff as reasonable, based on their considerable experience with projects at Sappi and their informal conversations with other companies that have completed similar types of projects at other facilities. A more detailed cost estimate is likely to increase the costs for installing and implementing either of the projects. Cost calculation spreadsheets for the SO_2 emission control measures are provided in Appendix C.

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[13] Ibid, Page 21.

The cost effectiveness analysis compares the annualized cost of the technology 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.

The resulting cost effectiveness calculations are summarized in Table 3-6.

Table 3-6: Power Boiler #9 SO_2 Control Cost Summary, per Unit Basis

Additional Emissions Control Measure	Total Capital Investment ($)	Total Annualized Costs ($/year)	Control Efficiency (%)	Annual Emissions Reduction (tpy)	Pollution Control Cost Effectiveness ($/ton)
Spray dryer absorption	$144,535,337	$24,484,747	70%	15.4	$1,589,900
Dry sorbent injection	$41,178,526	$5,672,396	50%	11.0	$5,672,396

Based on the information provided in Table 3-6 and in consideration of RHR analyses conducted in other states, the emission control measures were not considered cost effective.

Sections 3.2.4 through 3.2.6 provide a screening-level summary of the remaining three factors evaluated for the SO_2 emission control measures, understanding that these projects represent substantial capital investments that are not justified on a cost per ton or absolute cost basis.

3.2.4 Factor 2 – Time Necessary for Compliance

Factor #2 estimates the amount of time needed for full implementation of the different control measures. Typically, the time for compliance considers the time needed to develop and approve the new emissions limit into the SIP by state and federal action, then to implement the project necessary to meet the SIP limit via installation and tie-in of equipment for the emissions control measure.

The technologies would require significant resources and time of at least two to three years to engineer, permit, and install the equipment. The facility would attempt to complete the construction during a regularly scheduled outage but recognizes that the outage may need to be extended to install all required equipment.

The SIP is scheduled to be submitted in 2021 with the anticipated approval in 2022 (approximately one year after submittal). Once the SIP is approved, the design, engineer, procurement and installation schedule would begin. This would put the anticipated date of installation in 2024 or 2025.

3.2.5 Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance

The energy and non-air environmental impacts associated with implementation of the above identified SO_2 control measures are summarized below:

- Spray Dryer
    - Increased waste generation and disposal due to additional material collected in the particulate emissions control system
    - Increased truck and/or train traffic (reagent deliveries and waste hauling)
    - Water consumption for slurry
    - Electricity consumption (fans and pumps)

- Dry Sorbent injection
    - Increased waste generation and disposal due to additional material collected in the particulate emissions control system
    - Increased truck and/or train traffic (reagent deliveries and waste hauling)
    - Electricity consumption (fans and pumps)

3.2.6 Factor 4 – Remaining Useful Life of the Source

Because Power Boiler #9 is expected to continue operations for the foreseeable future, the useful life of the individual control measures (assumed 20-year life) was used to calculate emission reductions, amortized costs and cost effectiveness on a dollar per ton basis.

3.2.7 Proposed SO_2 Controls and Emissions Rates

This analysis does not support the installation of additional SO_2 emission control measures at Power Boiler #9 beyond those described in Section 2.3. As such, Sappi proposes to maintain the existing SO_2 permit limits presented in Table 2-2.

4 Recovery Boiler #10: Effective Controls Analysis

The 2019 SIP Guidance states that it "may be reasonable for a state not to select an effectively controlled source"[14] for the four-factor analysis with the rationale that "it is reasonable to assume for the purposes of efficiency and prioritization that a full four-factor analysis would likely result in the conclusion that no further controls necessary."[15] EPA identified potential scenarios that "EPA believes it may be reasonable for a state not to select a particular source for further analysis." However, EPA clarified that the associated scenarios are not a comprehensive list but are merely to illustrate examples for the state to consider.

One of the "effectively controlled" scenarios is for sources that went through a best available control technology (BACT) review with a construction permit issued on or after July 31, 2013.[16] EPA notes that the BACT control equipment review methodologies are "similar to, if not more stringent than, the four statutory factors for reasonable progress."[17]

Recovery Boiler #10 underwent a BACT review for NO_x, among other pollutants, and the associated construction permit was issued in 2017 (Air Permit 01700002-101), which is after the USEPA's July 31, 2013 scenario threshold date. Thus, this unit meets this scenario and is considered "effectively controlled" and, therefore, a four-factor analysis was not conducted. As such, Sappi proposes to maintain the existing NO_X permit limits presented in Table 2-3.

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[14] Ibid, Page 22.

[15] Ibid, Page 23.

[16] Ibid, Page 23.

[17] Ibid, Page 23.

5 Visibility Impacts Review

The Regional Haze Rule (RHR) requires that the SIP include an analysis of "baseline, current, and natural visibility conditions; progress to date; and the uniform rate of progress."[18] This is used to establish progress goals to be achieved by the end of the implementation period in 2028.[19] Section 5.1 provides an analysis of current visibility conditions at the three Class I areas near Sappi's facility: Boundary Waters, Voyageurs, and Isle Royale. Since 2009, the regional haze impairment at all three Class I areas has been declining (i.e., visibility has been improving). Additionally, regional haze impairment fell below the expected 2028 Universal Rate of Progress (URP) goal in 2016 for Boundary Waters and Isle Royale, and 2018 for Voyageurs. Because the existing visibility data demonstrates sustained progress towards visibility goals and the 5-year average visibility impairment on the most impaired days is already below the URP, the MPCA should use the current trend of emission reductions to demonstrate reasonable progress.

Additionally, the 2019 SIP Guidance provides criteria to evaluate when selecting sources that must complete an analysis of emission controls. One of the options for estimating baseline visibility impacts is a particle trajectory analysis.[20] In addition, the 2019 SIP Guidance says that a state can consider visibility impacts in Class I areas when evaluating possible emission control measures.[21] Section 5.2 provides results from two different particle trajectory analyses for the most impaired days at the Boundary Waters visibility monitor. The Boundary Waters area was selected because it is the closest Class I area to the Sappi facility. The results of the analysis conclude that Sappi provides a marginal contribution to visibility impairment at the nearby Class I areas. Thus, additional control measures implemented at Sappi are unlikely to provide a substantial improvement in visibility in the Class I areas.

5.1 IMPROVE Data Analysis

MPCA tracks progress towards the natural visibility conditions using data from the IMPROVE visibility monitors at Boundary Waters (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1).[22] The visibility metric is based on the 20% most anthropogenically impaired days and the 20% clearest days, with visibility being measured in deciviews (dv). The EPA issued guidance for tracking visibility progress, including the methods for selecting the "most impaired days," on December 20, 2018.[23] Originally, the RHR considered the "haziest days" but USEPA recognized that naturally occurring events (e.g., wildfires and dust storms)

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[18] 40 CFR 51.308(f)(1)

[19] 40 CFR 51.308(f)(3)

[20] Ibid, Page 13.

[21] Ibid, Page 34.

[22] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

[23] https://www.epa.gov/visibility/technical-guidance-tracking-visibility-progress-second-implementation-period-regional

could be contributing to visibility and that the "visibility improvements resulting from decreases in anthropogenic emissions can be hidden in this uncontrollable natural variability."[24]

Figure 5.1 through Figure 5.3 show the rolling 5-year average visibility impairment compared with the URP glidepath[25] at Boundary Waters (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1), respectively. Regional haze impairment has been declining since 2009 for all three Class I areas that are tracked by MPCA. Impacts to the most impaired days at Boundary Waters and Isle Royale fell below the expected 2028 URP goal in 2016 and have continued trending downward since. Voyageurs impaired days fell below the 2028 URP in 2018, and is also on a downward trend.

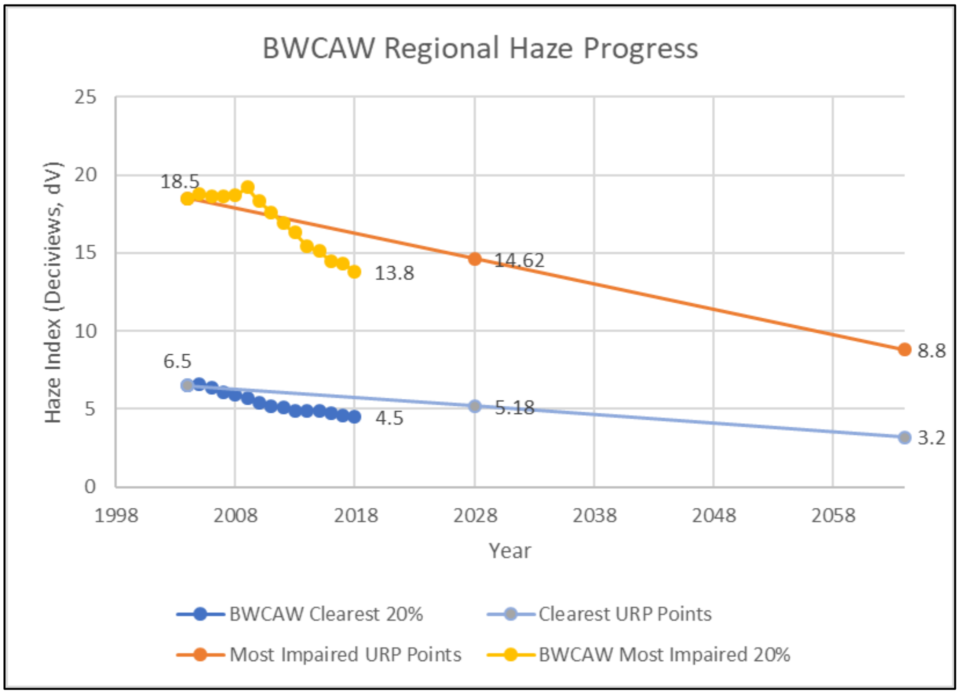

Figure 5.1: Visibility Trend versus URP – Boundary Waters Canoe Area (BOWA1)

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[24] USEPA, Federal Register, 05/04/2016, Page 26948

[25] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

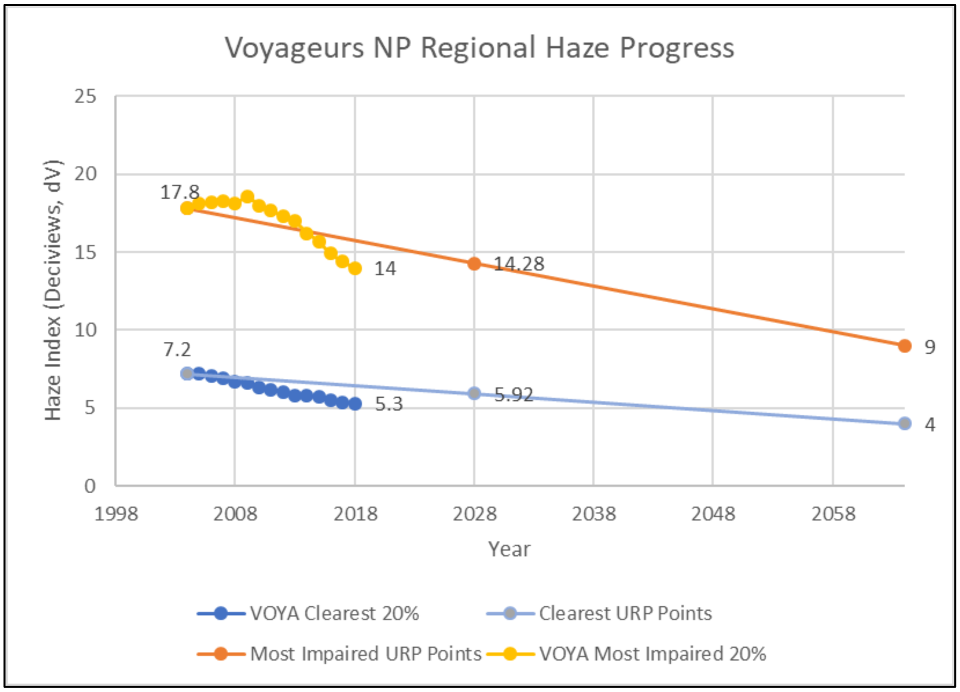

Figure 5.2: Visibility Trend versus URP – Voyageurs National Park (VOYA1)

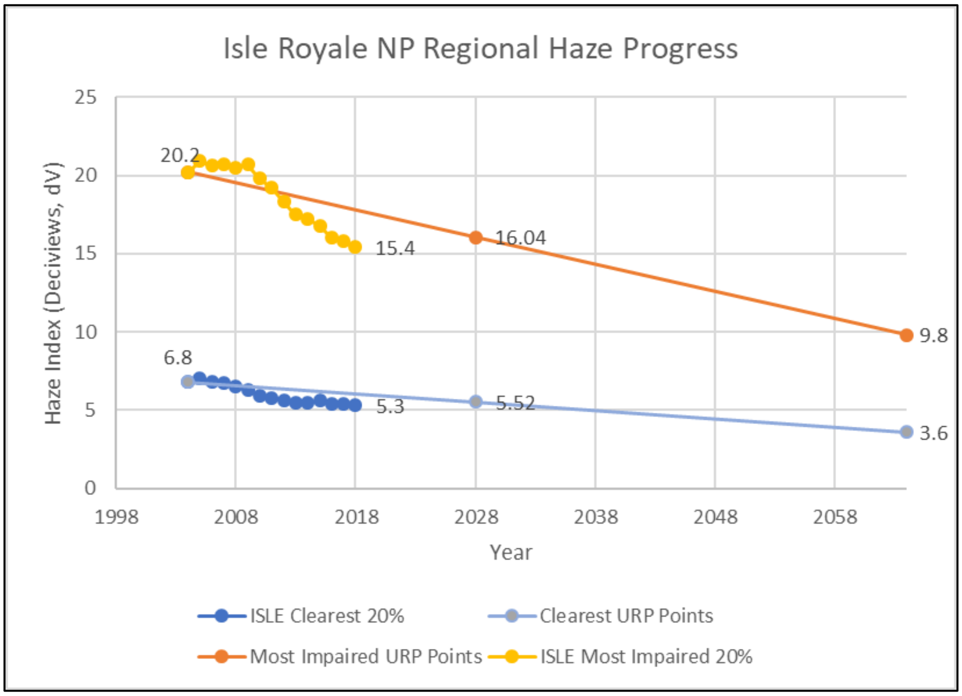

Figure 5.3: Visibility Trend versus URP – Isle Royale National Park (ISLE1)

The downward visibility trend for each of the Class I monitors described above can be mostly attributed to the reductions in ammonium sulfate and, to a lesser extent, ammonium nitrate as show in Figure 5.4. These reductions are a result of a number of different actions taken to reduce emissions from several sources, including:

- Installation of BART during the first RHR implementation period
- Emission reductions from a variety of industries, including pulp and paper mill sources, due to updated rules and regulations
- Transition of power generation systems from coal to natural gas and renewables (wind and solar)

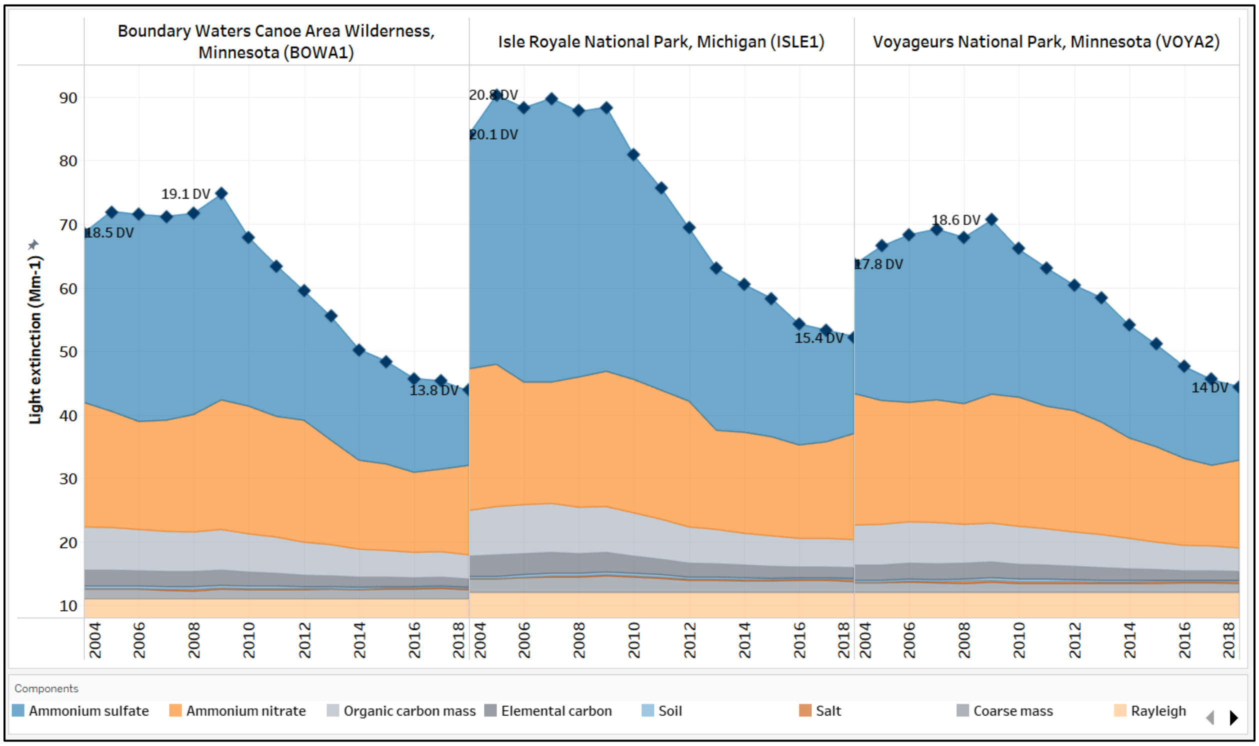

Figure 5.4: Visibility Components Trend for each Class 1 Monitor from 2004-2018[26]

Additionally, since the end of 2018, many facilities have implemented emission reduction actions that are not represented in the data in Figure 5.1 through Figure 5.4 including:

- Retiring two coal-fired boilers at the Minnesota Power Boswell Energy Center in Cohasset at the end of 2018

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[26] MPCA – Regional Haze Tableau Public. https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

- The compliance schedules for the NO_X emission reductions required by the Taconite Federal Implementation Plan (FIP) Establishing BART for Taconite Plants (40 CFR 52.1235)
- Other planned emission reduction projects that are scheduled to occur in Minnesota prior to 2028, such as the Xcel Energy boiler retirements as detailed in their Upper Midwest Integrated Resource Plan, 2020-2034

These emission reductions will further improve the visibility in the Class I areas, thus helping to ensure the trend remains below the URP to reach the 2028 visibility goal.

The 2019 Guidance says that the state will determine which emission control measures are necessary to make reasonable progress in the affected Class I areas.[27] Because the IMPROVE monitoring network data demonstrates sustained progress towards visibility goals and the 5-year average visibility impairment on the most impaired days is already below the URP, the MPCA should use the current trend of emission reductions to demonstrate reasonable progress.

5.2 Trajectory Analysis

The 2019 Guidance says that a state should estimate baseline visibility impacts in Class I areas when selecting which sources must conduct a four-factor analysis.[28] In addition, the 2019 Guidance says that a state can consider visibility impacts in Class I areas when evaluating possible emission control measures.[29] Barr conducted a trajectory analysis to provide insight as to the possible visibility impacts in the Boundary Waters due to emissions from Sappi. The Boundary Waters were selected as the closest Class I area.

A trajectory analysis considers the transport path of a particular air mass and the associated particles within the air mass to see if the air mass traveled over certain locations from specific source locations. The MPCA developed a tool[30] which calculates reverse trajectories from Class I areas in Minnesota for the "clearest" and "most impaired" days for 2007-2016 to help illustrate the influence of regional emissions on visibility. The reverse trajectories included in the MPCA tool were developed using the NOAA Hysplit model.[31] The trajectories consist of a single back trajectory for each "most impaired" day beginning at 18:00 and running back 48 hours with a starting height of 10 m.

Barr completed an analysis to determine which of MPCA's reverse trajectories from the Boundary Waters (BOWA1) monitor potentially crossed near Sappi to determine if the emissions from Sappi may have

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[27] Ibid, Page 9.

[28] Ibid, Page 12.

[29] Ibid, Page 34.

[30] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Regionalinfluence

[31] https://www.arl.noaa.gov/hysplit/hysplit/

influenced the visibility on the "most impaired" days at the monitor. Figure 5.5 summarizes the number of "most impaired" trajectories for each year and season from 2014-2016 (the most recent year with data available on the MPCA website) and the corresponding number of "most impaired" trajectories that crossed near Sappi. The trajectories which crossed near Sappi are presented in Figure 5.6.

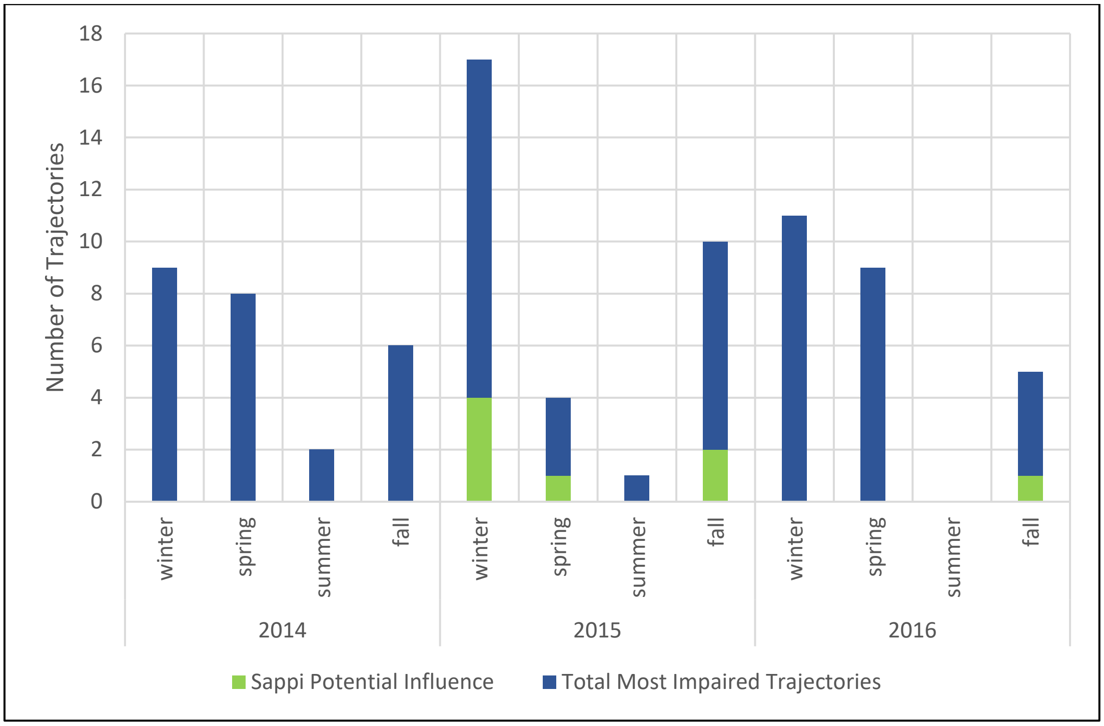

Figure 5.5: Total Number of Most Impaired Trajectories and Number that Cross Near Sappi for 2014-2016

Figure 5.6: Most Impaired Trajectories from MPCA Analysis that Cross Near Sappi in 2015-2016 (no trajectories cross near Sappi in 2014).

Based on the information provided in Figure 5.5, the number of trajectories originating from the Boundary Waters that cross near Sappi indicates that 84% of the time the trajectories did not cross near Sappi for the years analyzed (2014-2016). As expected, this percentage suggests that many sources and source regions other than Sappi are contributing to the visibility of the "most impaired" days at the monitor.

Furthermore, the characterization of potential impacts is a conservative representation as the trajectory only had to cross within 20-30 miles of Cloquet to be included. Also, the majority of the origins of the reverse trajectories are well beyond the Sappi facility location and thus could have influences, depending on the trajectory, from a variety of other sources and from nearby cities such as Duluth, St. Cloud, Rochester, and the Twin Cities (Figure 5.6).

Based on the information provided above, we can conclude that emissions from Sappi are not a primary contributor to visibility impairment on the most impaired days at the Boundary Waters. Thus, additional control measures implemented at Sappi are unlikely to provide a substantial improvement in visibility in the Class I areas.

Appendices

Appendix A

RBLC Search for Biomass Power Boilers for NO_X

Sappi Cloquet LLC
Appendix A : RBLC Search for Biomass Power Boilers for NOX

Pollutant Name: NOx
NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
AL-0250	BOISE WHITE PAPER	BOISE WHITE PAPER, LLC	AL	102-0001	322121	03/23/2010 ACT		COMBINATION BOILER	WOOD	435	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNERS	0.3	LB/MMBTU	3 H	BACT-PSD	130.5	LB/H	3 H	0		
*AR-0161	SUN BIO MATERIAL COMPANY	SUN BIO MATERIAL COMPANY	AR	2384-AOP-R0	322110	09/23/2019 ACT	A kraft paper mill designed with one high yield Kraft softwood Fiberline and two linerboard machiens. The plant is initially sized to support an approximate, nominal linerboard production capacity of 4,400 machine dry tons per day at varying base	Power Boiler	Biomass	1200	MMBtu/hr	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	0.06	LB/MMBTU	3-HOUR	BACT-PSD	0			0		
CA-1203	SIERRA PACIFIC INDUSTRIES-LOYALTON	SIERRA PACIFIC INDUSTRIES	CA	SAC 87-01-A	221119	08/30/2010 ACT	20 MW COGENERATION POWER PLANT	RILEY SPREADER STOKER BOILER - Transient Period (see notes)	WOOD	335.7	MMBTU/H	Nitrogen Oxides (NOx)	SELECTIVE NON-CATALYTIC REDUCTION (SNCR)	102	PPM	@12% CO2, 8-HR ROLLING AVG	BACT-PSD	65	LB/H	8-HR ROLLING AVG	0		
CA-1203	SIERRA PACIFIC INDUSTRIES-LOYALTON	SIERRA PACIFIC INDUSTRIES	CA	SAC 87-01-A	221119	08/30/2010 ACT	20 MW COGENERATION POWER PLANT	RILEY SPREADER STOKER BOILER	WOOD	335.7	MMBTU/H	Nitrogen Oxides (NOx)	SELECTIVE NON-CATALYTIC REDUCTION (SNCR)	80	PPM	@12% CO2, 8-HR ROLLING AVG	BACT-PSD	50.75	LB/H	8-HR ROLLING AVG	0		
CA-1225	SIERRA PACIFIC INDUSTRIES-ANDERSON DIVISION	SIERRA PACIFIC INDUSTRIES	CA	SAC 12-01	321113	04/25/2014 ACT	31 MW COGENERATION AND LUMBER MANUFACTURING FACILITY	STOKER BOILER (NORMAL OPERATION)	BIOMASS	468	MMBTU/H	Nitrogen Oxides (NOx)	SNCR	0.13	LB/MMBTU	12-MONTH ROLLING BASIS	BACT-PSD	0.15	LB/MMBTU	3-HOUR BLOCK AVERAGE	0		
CA-1225	SIERRA PACIFIC INDUSTRIES-ANDERSON DIVISION	SIERRA PACIFIC INDUSTRIES	CA	SAC 12-01	321113	04/25/2014 ACT	31 MW COGENERATION AND LUMBER MANUFACTURING FACILITY	STOKER BOILER (STARTUP & SHUTDOWN PERIODS)	BIOMASS	468	MMBTU/H	Nitrogen Oxides (NOx)	SNCR	70.2	LB/H	8-HR AVG (STARTUP PERIODS)	BACT-PSD	70.2	LB/H	8-HR AVG (SHUTDOWN PERIODS)	0		
CT-0156	MONTVILLE POWER LLC	NRG ENERGY	CT	107-0056	221119	04/06/2010 ACT	43 MW STOKER FIRED BIOMASS; 82 MW TANGENTIALLY FIRED NATURAL GAS/ULS DISTILLATE UTILITY BOILER (7% ANNUAL CAPACITY FACTOR)	42 MW Biomass utility boiler	Clean wood	600	MMBTU/H	Nitrogen Oxides (NOx)	Regenerative SCR	0.06	LB/MMBTU	24 HR BLOCK	LAER	0			0		
CT-0162	PLAINFIELD RENEWABLE ENERGY, LLC	PLAINFIELD RENEWABLE ENERGY, LLC	CT	145-0049	221119	12/29/2010 ACT	37.5 MW Biomass Power Plant	Fluidized Bed Gasification	Wood	523.1	MMBtu/hr	Nitrogen Oxides (NOx)	SNCR	0.075	LB/MMBTU		LAER	45.3	PPMVD @7% O2	24 HR BLOCK	0		
GA-0141	WARREN COUNTY BIOMASS ENERGY FACILITY	OGETHORPE POWER CORPERATION	GA	4911-301-0016-P-01-0	221119	12/17/2010 ACT	The proposed project will include: a bubbling fluidized bed boiler with a maximum total heat input capacity of 1,399 MMBTU/H, 2 fire water pump emergency engines; a raw material handling & storage area; a sorbent storage silo; a boiler bed sand silo, a sand	Boiler, Biomass Wood	Biomass wood	100	MW	Nitrogen Oxides (NOx)	Selective non-catalytic reduction system (SNCR)	0.1	LB/MMBTU	30 D ROLLING AV / CONDITION 2.9	BACT-PSD	648	TONS	12 MONTH ROLLING TOTAL / CONDITION 2.18	0		
*KS-0034	ABENGOA BIOENERGY BIOMASS OF KANSAS (ABBK)	ABENGOA BIOENERGY BIOMASS OF KANSAS (ABBK)	KS	C-11396	325193	05/27/2014 ACT	Abengoa Bioenergy Biomass of Kansas (ABBK) intends to install and operate a biomass-to-ethanol and biomass-to-energy production facility near Hugoton, Kansas.	biomass to energy cogeneration bioler	different types of biomass	500	MMBtu/hr	Nitrogen Oxides (NOx)	Selective Catalytic Reduction System (SCR) and an over-fire system (OFA)	0.3	LB/MMBTU	30-DAY ROLLING, INCLUDES SSM	BACT-PSD	157.5	LB/HR	1-HR AVE, INCLUDES SSM	0		
ME-0037	VERSO BUCKSPORT LLC	VERSO BUCKSPORT LLC	ME	A-22-77-4-A	322121	11/29/2010 ACT	Existing pulp (groundwood and thermomechanical) and paper making facility.	Biomass Boiler 8	Biomass	814	MMBTU/H	Nitrogen Oxides (NOx)	SNCR	0.15	LB/MMBTU	30 DAY ROLLING	BACT-PSD	244.2	LB/H		0		

Appendix B

Power Boiler #9 – Control Cost Calculations for NO_X

Sappi Cloquet LLC
Boiler #9
Appendix B - NO_X SNCR Calculations

	Boiler 9		Comment
Max Firing Rate	430	MMBtu/hr	PTE Calculations for Boiler 9
NO_X Emission Rate (Uncontrolled)	0.292	lb/MMBtu	2019 Emission Inventory
System Capacity Factor (Actual rate vs. max firing rate at 8760)	63.1%		2019 actual fuel per year / Maximum fuel per year (See "SCR Design Parameters")
Uncontrolled Emissions	347.0	ton/year	Calculated from Above
Control Efficiency	25.0%		From "Data Inputs"
NO_X Controls Emission Rate	0.219	lb/MMBtu	Calculated from Above
Controlled Emissions	260.3	ton/year	Calculated from Above
Total Capital Investment (TCI)	$5,021,391		From "Cost Estimate"
Total Annual Cost (TAC) =	$623,834	per year in 2020 dollars	
NOx Removed =	86.8	tons/year	Calculated from above
Current Retrofit Factor =	1.33		From "Data Inputs"
Cost Effectiveness =	$7,191	per ton of NOx removed in 2020 dollars	From "Cost Estimate"

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial ▼

What type of fuel does the unit burn? Coal ▼

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit ▼

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.33

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 430.0 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 4,597 Btu/lb

What is the estimated actual annual fuel consumption? 536,062,322 lbs/Year

Is the boiler a fluid-bed boiler? No ▼

Enter the net plant heat input rate (NPHR) 10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Lignite ▼

Enter the sulfur content (%S) = 0.05 percent by weight

or

Select the appropriate SO_2 emission rate: < 3lb/MMBtu ▼

Ash content (%Ash): 2.8 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})		days
Inlet NO_x Emissions (NOx_{in}) to SNCR		lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SNCR		lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)		

Plant Elevation	1083	Feet above sea level

25.0% Control Efficiency

Concentration of reagent as stored (C_{stored})		Percent
Density of reagent as stored (ρ_{stored})		lb/ft^3
Concentration of reagent injected (C_{inj})		percent
Number of days reagent is stored ($t_{storage}$)		days
Estimated equipment life		Years

Select the reagent used Ammonia ▼

Enter the cost data for the proposed SNCR:

Desired dollar-year	2020			
CEPCI for 2020	607.5	2019 Final CEPCI value	541.7	2016 CEPCI
Annual Interest Rate (i)	5.5	Percent*		
Fuel ($Cost_{fuel}$)	1.74	\$/MMBtu*		
Reagent ($Cost_{reag}$)	0.29	\$/gallon for a 29 percent solution of ammonia		
Water ($Cost_{water}$)	0.0042	\$/gallon*		
Electricity ($Cost_{elect}$)	0.0676	\$/kWh*		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	48.80	\$/ton*		

CEPCI = Chemical Engineering Plant Cost Index

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/MMBtu)	1.74	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Ash Disposal Cost ($/ton)	48.8	Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft Demand. July 11, 2017. Available at: http://www.wastebusinessjournal.com/news/wbj20170711A.htm.	
Percent sulfur content for Coal (% weight)	0.82	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Percent ash content for Coal (% weight)	13.60	Average ash content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	6,685	Select type of coal	
Interest Rate (%)	5.5	Default bank prime rate	

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	430	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	819,334,091	lbs/Year
Actual Annual fuel consumption (Mactual) =		536,062,322	lbs/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.00	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.631	fraction
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	5527	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	25	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	31.39	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	86.75	tons/year
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.07	
SO_2 Emission rate =	$(\%S/100)x(64/32)*(1x10^6)/HHV$ =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.04	
Atmospheric pressure at 1083 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.1	psia
Retrofit Factor (RF) =	Retrofit to existing boiler	1.33	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	141	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/C_{sol} =	485	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	64.8	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	21,800	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n$/$(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	17.9	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	110	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	1.14	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/HHV =	6.9	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$3,862,609	in 2020 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2020 dollars
Balance of Plant Costs (BOP_{cost}) =	$0	in 2020 dollars
Total Capital Investment (TCI) =	$5,021,391.50	in 2020 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

SNCR Capital Costs ($SNCR_{cost}$) =	$3,862,609	in 2020 dollars (Jansen report 2012 equipment scaled to 2020 $)

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0	in 2020 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$0	in 2020 dollars

Annual Costs

Direct Annual Costs (DAC) =	
Indirect Annual Costs (IDAC) =	
Total annual costs (TAC) = DAC + IDAC	

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	
Direct Annual Cost =		

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	
Capital Recovery Costs (CR)=	CRF x TCI =	
Indirect Annual Cost (IDAC) =	AC + CR =	

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$623,834	per year in 2020 dollars
NOx Removed =	87	tons/year
Cost Effectiveness =	$7,191	per ton of NOx removed in 2020 dollars

Appendix C

RBLC Search for Biomass Power Boilers for SO_2

Sappi Cloquet LLC
Appendix C: RBLC Search for Biomass Power Boilers for SO2

Pollutant Name: SO2

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
*AR-0161	SUN BIO MATERIAL COMPANY	SUN BIO MATERIAL COMPANY	AR	2384-AOP-R0	322110	09/23/2019 ACT	A kraft paper mill designed with one high yield Kraft softwood Fiberline and two linerboard machiens. The plant is initially sized to support an approximate, nominal linerboard production capacity of 4,400 machine dry tons per day at varying base	Power Boiler	Biomass	1200	MMBtu/hr	Sulfur Dioxide (SO2)	FGD/Dry Sorbent Injection	0.025	LB/MMBTU	3 1-HOUR TESTS	BACT-PSD	0			0		
CT-0156	MONTVILLE POWER LLC	NRG ENERGY	CT	107-0056	221119	04/06/2010 ACT	43 MW STOKER FIRED BIOMASS; 82 MW TANGENTIALLY FIRED NATURAL GAS/ULS DISTILLATE UTILITY BOILER (7% ANNUAL CAPACITY FACTOR)	42 MW Biomass utility boiler	Clean wood	600	MMBTU/H	Sulfur Oxides (SOx)	Low sulfur fuels	0.025	LB/MMBTU	3 HR BLOCK	BACT-PSD	0			0		
CT-0162	PLAINFIELD RENEWABLE ENERGY, LLC	PLAINFIELD RENEWABLE ENERGY, LLC	CT	145-0049	221119	12/29/2010 ACT	37.5 MW Biomass Power Plant	Fluidized Bed Gasification	Wood	523.1	MMBtu/hr	Sulfur Dioxide (SO2)	Spray Dryer, Bed Injection	0.035	LB/MMBTU		OTHER CASE-BY-CASE	15.4	PPMVD @7% O2	3 HR BLOCK	0		
GA-0141	WARREN COUNTY BIOMASS ENERGY FACILITY	OGETHORPE POWER CORPERATION	GA	4911-301-0016-P-01-0	221119	12/17/2010 ACT	The proposed project will include: a bubbling fluidized bed boiler with a maximum total heat input capacity of 1,399 MMBTU/H, 2 fire water pump emergency engines; a raw material handling & storage area; a sorbent storage silo; a boiler bed sand silo, a sand	Boiler, Biomass Wood	Biomass wood	100	MW	Sulfur Oxides (SOx)	Dust sorbent injection system	0.01	LB/MMBTU	30 D ROLLING AV / CONDITION 2.12	BACT-PSD	56	TONS	12 MONTH ROLLING TOTAL / CONDITION 2.20	0		
*KS-0034	ABENGOA BIOENERGY BIOMASS OF KANSAS (ABBK)	ABENGOA BIOENERGY BIOMASS OF KANSAS (ABBK)	KS	C-11396	325193	05/27/2014 ACT	Abengoa Bioenergy Biomass of Kansas (ABBK) intends to install and operate a biomass-to-ethanol and biomass-to-energy production facility near Hugoton, Kansas.	biomass to energy cogeneration bioler	different types of biomass	500	MMBtu/hr	Sulfur Dioxide (SO2)	Injection of sorbent (lime) in combination with a dry flue gas desulfurization (FGD) system	0.21	LB/MMBTU	30-DAY ROLLING, INCLUDES SSM	BACT-PSD	110.25	LB/HR	MAX 1-HR, INCLUDES SS, EXCLUDES MALFUNCT	0		
LA-0249	RED RIVER MILL	INTERNATIONAL PAPER CO	LA	PSD-LA-562(M-4)	322130	05/09/2011 ACT	KRAFT PULP MILL WHICH PRODUCES UNBLEACHED LINERBOARD	NO. 2 HOGGED FUEL BOILER	HOGGED FUEL/BARK	992.43	MMBTU/H	Sulfur Dioxide (SO2)	USE OF LOW SULFUR FUELS	60	LB/H	HOURLY MAXIMUM	BACT-PSD	262.8	T/YR	ANNUAL MAXIMUM	0.06	LB/MMBTU	
ME-0037	VERSO BUCKSPORT LLC	VERSO BUCKSPORT LLC	ME	A-22-77-4-A	322121	11/29/2010 ACT	Existing pulp (groundwood and thermomechanical) and paper making facility.	Biomass Boiler 8	Biomass	814	MMBTU/H	Sulfur Dioxide (SO2)	0.7% sulfur when firing oil	0.8	LB/MMBTU	3-HR AVERAGE	BACT-PSD	651.2	LB/H		0		

Appendix D

Power Boiler #9 – Control Cost Calculations for SO_2

Sappi Cloquet LLC

Appendix D, Table 1 - Unit Summary

Unit	**Boiler 9**	
Maximum Hourly Heat Input Rate	430	MMBtu/hr
Exhaust Flow Rate	271,905	acfm
Exhaust Temperature	413	º F
Exhaust Moisture Content	15%	
Atmospheric Pressure at Elevation	14.1	psia
Capacity Factor (CF) / Utilization	70%	
Expected Annual Hours of Operation	8760	hours
Baseline Emission Rate	0.02	lb/MMBtu
Hourly Emissions (average annual rate)	7.2	lb/hr
Annual Emissions (estimated 2028 emissions)	22.0	tons/yr
Annual Interest Rate	5.25%	

Control Equipment Costs

Control Technology Name		**Spray Dry Absorption**	**Dry Sorbent Injection**
Expected Equipment Life (years)		20	20
SO_2 Control Efficiency		70%	50%
Controlled Emissions (tons/yr)		6.6	11.0
Reduction (tons/yr)		15.4	11.0
Notes on Technology			
Capital Costs			
Direct Capital Costs (DC)	[1]		
Indirect Capital Costs (IC)	[1]		
Total Capital Investment (TCI = DC + IC)	[1]	$144,535,337	$41,178,526
Operating Costs			
Direct Operating Costs ($/year)	[2]	-	$408,630
Indirect Operating Costs ($/year)	[3]	-	$5,263,766
Total Annual Cost ($/year)	[4]	$24,484,747	$5,672,396
Control Cost Effectiveness ($/ton)		***$1,589,900***	***$515,700***

Footnotes

[1] See individual control cost summary tables

[2] Labor, supervision, materials, replacement parts, utilities, etc.

[3] Sum indirect oper costs + capital recovery cost

[4] Total Annual Cost = Direct Operating Costs + Indirect Operating Costs

[5] Controlled Emissions = (1 - Control Efficiency) * Baseline Emissions

[6] Control Cost Effectiveness = Total Annual Cost / Tons Removed from Exhaust

Sappi Cloquet LLC

Appendix D, Table 2 - Spray Dry Absorption

Unit	Boiler 9	
Maximum Hourly Heat Input Rate	430	MMBtu/hr
Exhaust Flow Rate	271,905	acfm
Standardized Flow Rate	164,451	scfm @ 68F
Dry Std Flow Rate	139,783	scfm @ 68F
Exhaust Temperature	413	º F
Exhaust Moisture Content	15%	
Atmospheric Pressure at Elevation	14.1	psia
Capacity Factor (CF) / Utilization	70%	
Expected Annual Hours of Operation	8760	hours
Baseline Emission Rate	0.02	lb/MMBtu
Hourly Emissions (*permitted limit)	7.2	lb/hr
Annual Emissions	22.0	tons/yr
Volumetric Flow Rate SO2 (VFR_{SO2})	0.7	scfm SO2
Concentration SO2 (C_{SO2})	4.3	ppmvd
Annual Interest Rate	5.25%	
Control Equipment Life	20	yrs

CONTROL EQUIPMENT COSTS: Equation Type 19 for SO2 - ICI Boilers; SDA

Capital Cost	
Capital Cost	$144,535,336.50
CRF	0.08
Annualized Capital Cost	**$11,845,000.82**
Operating Costs	
Fixed O&M	
Variable O&M	
Total Annualized Cost	**$24,484,746.56**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual Ton/Yr	Cont Eff %	Cont Emis Ton/Yr	Reduction Ton/Yr	Cont Cost $/Ton Rem
Sulfur Dioxide (SO2)	9.40	22.00	0.70	6.60	15.40	**$1,589,919**

Notes & Assumptions

1 Total Capital Investment

$$TCI = [143.76(Fd)] + \left[0.61\left(\frac{\sqrt{Fd}}{\#Ducts}\right)^2\right] + \left[17412.26e^{0.017\left(\frac{\sqrt{Fa}}{\#Ducts}\right)}\right] + [53.973e^{0.014\left(\frac{\sqrt{Fa}}{\#Ducts}\right)}]+931911.04$$

where #Ducts = :	1	if Fd ≤ 154,042
	Fd/154,042	Fd > 154,042

2 Total Annualized Cost

$$TAC = (Op_{hrs})\{[(1.62x10^{-3})(F_d)]+[(6.84x10^{-7})(C_{SO2})(F_d)]+[(3.72x10^{-5})(F_a)]+21.157)\}+\{[7.2X10^{-2}+CRF]xTCI\}$$

3

Chemical Engineerig Magazine Plant Cost Index		
Historical Date/Cost Index	2008	575.4
Current Date/Cost Index	2019	591.1
Inflation Adjustment		1.03

Sappi Cloquet LLC

Appendix D, Table 3 - Dry Sorbent Injection

Operating Unit: **Boiler 9**

Emission Unit Number			Stack/Vent Number			**Alt Op Para #1**	**Alt Op Para #2**
Design Capacity	430	MMBtu/hr	Standardized Flow Rate		scfm @ 32º F		
Utilization Rate	70%		Exhaust Temperature	413	Deg F		
Annual Operating Hours	8,760	hr/yr	Exhaust Moisture Content	15%			
Annual Interest Rate	5.25%		Actual Flow Rate	271,905	acfm		
Control Equipment Life	20	yrs	Standardized Flow Rate	164,451	scfm @ 68º F		
Plant Elevation	-	ft	Dry Std Flow Rate	139,783	dscfm @ 68º F		
Atmospheric Pressure at Elevation	14.10	psia					

Chemical Engineerig Magazine Plant Cost Index		
Historical Date/Cost Index	1997	386.5
Current Date/Cost Index	2019	591.1
Inflation Adjustment		1.53

CONTROL EQUIPMENT COSTS

Capital Costs									
Direct Capital Costs								**Equipment**	
Purchased Equipment (A)					Scaled from DC from IAPCS program estimate			$10,690,976.67	**$16,350,417.36**
Purchased Equipment Total (B)	15%	of control device cost (A)							**$18,802,979.97**
Installation - Standard Costs	74%	of purchased equip cost (B)							$13,914,205.17
Installation - Site Specific Costs									N/A
Installation Total									$13,914,205.17
Total Direct Capital Cost, DC									$32,717,185.14
Total Indirect Capital Costs, IC	45%	of purchased equip cost (B)							$8,461,340.98
Total Capital Investment (TCI) = DC + IC									**$41,178,526.13**
Operating Costs									
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.							$408,629.74
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost							$5,263,766.17
Total Annual Cost (Annualized Capital Cost + Operating Cost)									**$5,672,395.91**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual Ton/Yr**	**Calculation Method**	**Cont Eff %**	**Performance Basis**	**Conc. Units**	**Cont Emis Ton/Yr**	**Reduction Ton/Yr**	**Cont Cost $/Ton Rem**
Sulfur Dioxide (SO2)	7.18	22.00	% Removal	0.50			11.00	11.00	$515,700

Notes & Assumptions

1. Total Direct Capital Cost Estimated using the Integrated Air Pollution Control Sytem Program Version 5a and adjusted for inflation based on Chemical Engineering Plant Cost Index
2. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1
3. Compressed air for baghouse assumed to be 2 scfm / 1000 acfm EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1.5.1.8
4. Bag replacement at 10 min/bag EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4 lists replacement times from 5 - 20 min per bag.
5. Dry scrubbing SO2 costs include addition of a baghouse. Assumed that the existing ESP could not handle additional loading.
6. For units of measure, k = 1,000 units, MM = 1,000,000 units e.g. kgal = 1,000 gal
7. Solid waste disposal cost is only for spent lime.
8. Used 0.6 power law factor to adjust prices based on acfm from bid basis

Sappi Cloquet LLC

Appendix D, Table 3 - Dry Sorbent Injection

CAPITAL COSTS

Direct Capital Costs			
Purchased Equipment (A) [1]			**$16,350,417.36**
Purchased Equipment Costs (A) - Injection System + auxiliary equipment, EC			
Instrumentation	10%	of control device cost (A)	$1,635,041.74
State Sales Taxes	0.0%	of control device cost (A)	-
Freight	5%	of control device cost (A)	$817,520.87
Purchased Equipment Total (B)	15%		**$18,802,979.97**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	$752,119.20
Handling & erection	50%	of purchased equip cost (B)	$9,401,489.98
Electrical	8%	of purchased equip cost (B)	$1,504,238.40
Piping	1%	of purchased equip cost (B)	$188,029.80
Insulation	7%	of purchased equip cost (B)	$1,316,208.60
Painting	4%	of purchased equip cost (B)	$752,119.20
Installation Subtotal Standard Expenses	74%		**$13,914,205.17**
Site Preparation, as required	N/A	Site Specific	-
Buildings, as required	N/A	Site Specific	-
Site Specific - Other	N/A	Site Specific	
Total Site Specific Costs			N/A
Installation Total			**$13,914,205.17**
Total Direct Capital Cost, DC			**$32,717,185.14**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	$1,880,298.00
Construction & field expenses	20%	of purchased equip cost (B)	$3,760,595.99
Contractor fees	10%	of purchased equip cost (B)	$1,880,298.00
Start-up	1%	of purchased equip cost (B)	$188,029.80
Performance test	1%	of purchased equip cost (B)	$188,029.80
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	3%	of purchased equip cost (B)	$564,089.40
Total Indirect Capital Costs, IC	45%	of purchased equip cost (B)	**$8,461,340.98**
Total Capital Investment (TCI) = DC + IC			**$41,178,526.13**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**$41,178,526.13**

OPERATING COSTS

Direct Annual Operating Costs, DC			
Operating Labor			
Operator	34.36	$/Hr	$188,125.38
Supervisor	0.15	of Op Labor	$28,218.81
Maintenance			
Maintenance Labor	28.45	$/Hr	$93,453.65
Maintenance Materials	100	% of Maintenance Labor	$93,453.65
Utilities, Supplies, Replacements & Waste Management			
Electricity	492.15	kW-hr	$2,407.63
Compressed Air	2.00	scfm/kacfm	$958.43
Solid Waste Disposal	0.00	ton/hr	$4.02
Lime	6.91	lb/hr	$20.12
Filter Bags	198.00	bags	$1,988.06
Total Annual Direct Operating Costs			**$408,629.74**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	$241,950.89
Administration (2% total capital costs)	2%	of total capital costs (TCI)	$823,570.52
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	$411,785.26
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	$411,785.26
Capital Recovery	0.0820	for a 20-year equipment life and a 5.25% interest rate	$3,374,674.23
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**$5,263,766.17**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**$5,672,395.91**

See summary page for notes and assumptions

Sappi Cloquet LLC

Appendix D, Table 3 - Dry Sorbent Injection

Capital Recovery Factors

Primary Installation		
Interest Rate	5.25%	
Equipment Life	20	years
CRF	0.0820	

Replacement Parts & Equipment: **Filter bags & cages**

Equipment Life	5	years	
CRF	0.2326		
Rep part cost per unit	33.71	$/bag	
Amount Required	198	cages	
Total Rep Parts Cost	7,008	Cost adjusted for freight & sales tax	
Installation Labor	1,540	10 min per bag, Labor + Overhead (64%)	EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**8,548**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag.
Annualized Cost	**1,988**		

Summary of "Other" site specific Costs

Item	**Cost**	**Description**
1		*e.g. New Fan, new stack, etc.*
2		
3		
4		
5		
6		
Total	$0	

Electrical Use

	Flow acfm		D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	271,905		10			492.1	
Baghouse Shaker	0	Gross fabric area ft^2				0.0	EPA Cont Cost Manual 6th ed Section 6 Chapter 1 Eq 1.14
Total						492.1	

Reagent Use & Other Operating Costs

Lime Use	7.18	lb/hr SO2	0.96	lb Lime/lb SO2	6.91	lb/hr Lime
Water Makeup Rate/WW Disch =			gpm			

Baghouse Filter Cost See Control Cost Manual Sec 6 Ch 1 Table 1.8 for bag costs

Gross BH Filter Area	2,655	ft					
Cages	10 ft long	5 in dia	13.42	area/cage ft^2	198 Cages	11.04	$/cage
Bags	1.69	$/ft2 of fabric				22.68	$/bag
Total						33.71	

Operating Cost Calculations

Utilization Rate	1%	Annual Operating Hours	8,760

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***		**Annual Cost**	**Comments**
Operating Labor								
Op Labor	34.36	$/Hr	5.0	hr/8 hr shift	5,475	$	188,125	$/Hr, 5.0 hr/8 hr shift, 5,475 hr/yr
Supervisor	15%	of Op Labor			NA	$	28,219	% of Operator Costs
Maintenance								
Maint Labor	28.45	$/Hr	3.0	hr/8 hr shift	3,285	$	93,454	$/Hr, 3.0 hr/8 hr shift, 3,285 hr/yr
Maint Mtls	100%	of Maintenance Labor			NA	$	93,454	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management								
Electricity	0.080	$/kW-h	492.1	kW-hr	30,178	$	2,408	$/kW-h, 492 kW-hr, 8760 hr/yr, 0.7% utilization
Natural Gas	3.770	$/kscf	N/A					
Water	0.340	$/kgal	0	gpm	0	$	-	$/kgal, 0 gpm, 8760 hr/yr, 0.7% utilization
Cooling Water	0.419	$/kgal	N/A					
Compressed Air	0.479	$/kscf	2	scfm/kacfm	2,001	$	958	$/kscf, 2 scfm/kacfm, 8760 hr/yr, 0.7% utilization
Wastewater Disposal Neutralization	2.554	$/kgal	0	gpm	0	$	-	$/kgal, 0 gpm, 8760 hr/yr, 0.7% utilization
Wastewater Disposal Biotreatment	6.469	$/kgal	N/A					
Solid Waste Disposal	19.002	$/ton	0.0	ton/hr	0	$	4	$/ton, 0 ton/hr, 8760 hr/yr, 0.7% utilization
Hazardous Waste Disposal	425.608	$/ton	N/A					
Lime	95.00	$/ton	6.9	lb/hr	0	$	20	$/ton, 7 lb/hr, 8760 hr/yr, 0.7% utilization
Filter Bags	57.39	$/bag	198.0	bags	N/A	$	1,988	$/bag, 198 bags, 8760 hr/yr, 0.7% utilization

See Summary page for notes and assumptions

sappi

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Hassan Bouchareb
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155-4194

July 28, 2021

Re: Response to Four-Factor Analysis Review/Questions dated June 7th and 14th, 2021

Mr. Bouchareb:

On July 17th, 2020, Sappi Cloquet LLC (Sappi) submitted a Regional Haze Four-Factor Analysis (FFA) report in response to your request for information letter dated January 29th, 2020. Sappi understands that the FFA report is being used by Minnesota Pollution Control Agency (MPCA) to inform decisions for the Regional Haze State Implementation Plan (SIP) regarding what emission reductions are necessary to make reasonable progress.

This letter is in response to your June 7th and 14th, 2021 emails which requested clarification regarding specific information that was included in Sappi's FFA report. This information below addresses the "request summary" in your June 14th email which were based on specific comments that you received from the MPCA technical reviewer, the U.S. Environmental Protection Agency (EPA) and the Federal Land Managers (FLMs).

Question 1. Cost Spreadsheets

a. Please provide a copy of the cost estimation spreadsheet for Boiler #9 SCR

Attached electronically is an editable spreadsheet containing the control cost calculations for the installation of selective catalytic reduction (SCR) NO_X controls on the No. 9 Power Boiler at Sappi.

b. Please provide a copy of the 2012 "Jansen Report"

Attached electronically is a copy of the Jansen Report, which is an engineering study prepared in 2011 for definition engineering and Class 10 cost estimate for the installation of selective non-catalytic reduction (SNCR) NO_X controls on the No. 9 Power Boiler at Sappi.

Question 2 – Retrofit Factor

a. Please provide additional information regarding the choice of retrofit factor and how you arrived at that value

Retrofit factors are intended to provide an estimate of additional costs that would be incurred to install air pollution control equipment at a facility because the facility was not originally designed and built to accommodate the control equipment. EPA states that retrofit factors should be reserved for those items directly related to demolition, fabrication, and installation. A retrofit factor of 1 is typically used for a site that will experience minimal retrofit issues while retrofit factors of 1.5 and 1.6 have been used for cost estimates for pollution control equipment installation at older facilities with limited space to accommodate the design and installation of new equipment. Sappi's control cost analysis for No. 9 Power Boiler used a retrofit factor 1.00 for SO_2 controls (Spray Dry Absorption and Dry Sorbent Injection) and 1.33 for NO_X controls (SCR and SNCR).

The retrofit factor of 1.00 for SO_2 control technologies is a conservative approach that was used due to the high cost-effectiveness (dollars per ton of potential pollutant removed) that resulted from the control cost calculations. In other words, because the cost-effectiveness was so high, the retrofit factor was not further investigated or applied.

The retrofit factor of 1.33 for NO_X controls is justified because No. 9 Power Boiler is an older emission unit that was not designed to accommodate additional controls such as SCR or SNCR. The retrofit factor was used to account for additional costs that were not otherwise considered in the cost effectiveness calculations. For example, site preparation at the facility will likely incur higher than anticipated costs for demolition and equipment removal from an existing boiler. In addition, the detailed design would likely require redesign and relocation of pipe racks, duct work, and other equipment. Furthermore, additional or enhanced structural support may be necessary to accommodate the equipment.

Regarding the SNCR cost analysis, the retrofit factor was also intended to address equipment that was not included in the original cost estimate. The cost estimate was based on the Jansen Report which provided a list of items that were not included as stated on page 5-1:

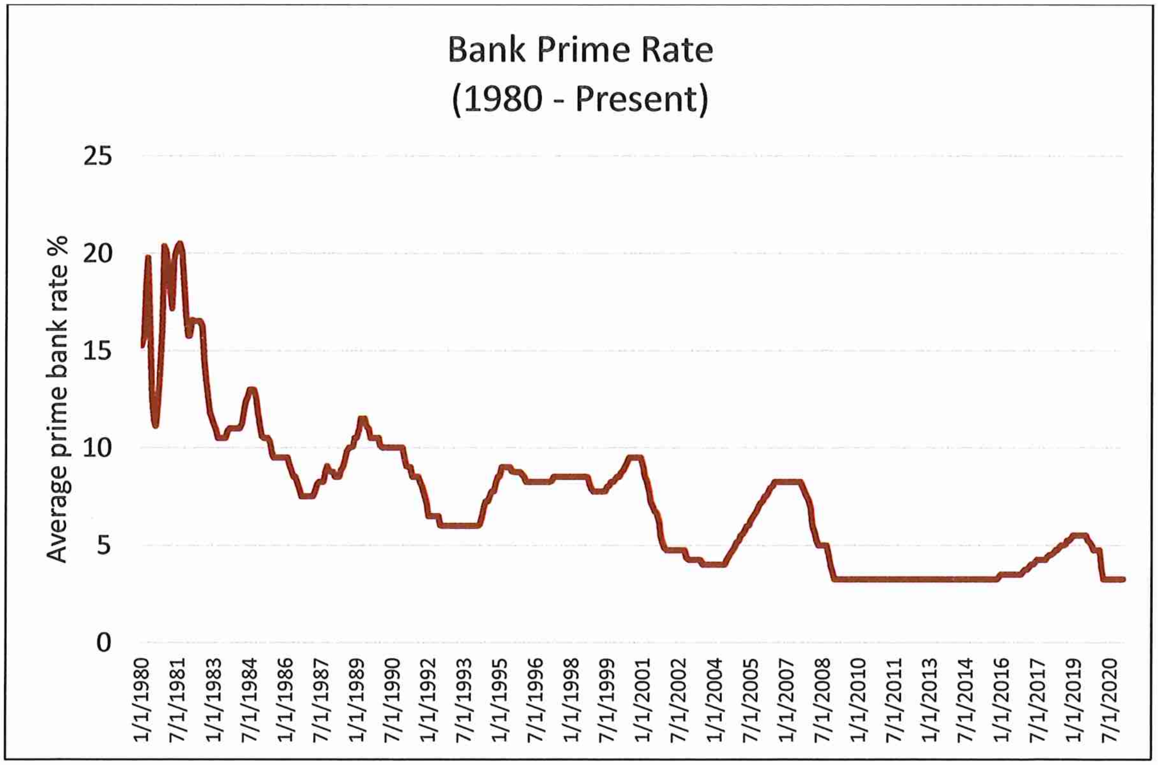
> *"Certain items that may be required as part of the overall upgrade project have been excluded from the scope of preliminary engineering, are provided by others, or are otherwise not included as a part of this cost estimate.*
>
> - *Instrument air supply to equipment.*
> - *Electrical and signal control cabling material supply.*
> - *Instrumentation pneumatic tubing material supply.*
> - *Structural engineering and material supply.*
> - *Foundation material supply.*
> - *Boiler chemical cleaning, if required.*
> - *Taxes, fees, or permit costs.*
> - *Sappi project engineering, administration, or other project indirect costs.*
> - *Hazardous material testing, abatement of disposal.*
> - *Heat tracing and insulation.*
> - *Repairs of existing equipment unless specifically addressed in this report."*

The use of a higher retrofit factor, such as 1.5 and 1.6, was also considered but additional investigation of the site would have been necessary and, therefore, was not applied at this time.

Question 3 – Interest Rate

a. **Revise control cost estimates to use the current prime interest rate (3.25%) per the control cost manual suggested default or provide supporting documentation to support the 5.5% interest rate used in the current analyses**

The prime interest rate can frequently change and the current rate of 3.25% is a historic low value. For example, the bank prime rate was at 5.5% as recently as July 2019 and was at 4.75% in February 2020 before dropping to the current 3.25% in April 2020. Although 3.25% may be available today, the historic volatility in the prime interest rate suggest that this value may not be available when financing an emission reduction project that would be scheduled for startup by 2028.[1] Based on this volatility and uncertainty, Sappi is justified in using an interest rate of 5.5% to represent a reasonable estimate of the future cost of capital for these analyses.



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[1] MPCA has stated that emission reduction projects identified in the 2021 SIP update must be installed prior to the next SIP update in 2028.

Please let us know if you need any additional information or would like to discuss this submittal in more detail.

Sincerely,

Tom Radovich
Managing Director
Cloquet Operations

--- submitted electronically ---

Attachments:

- SCR Control Cost Spreadsheet for No. 9 Power Boiler
- Jansen Report for Installation of SNCR on No. 9 Power Boiler

Attachment 1

SCR Control Cost Spreadsheet for No. 9 Power Boiler

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	430	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	819,334,091	lbs/Year
Actual Annual fuel consumption (Mactual) =		517,045,435	lbs/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.00	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.631	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	5528	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	80.1	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	100.62	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	278.12	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.00	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	177,016	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	33.79	/hour
Residence Time	1/V_{space}	0.03	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.07	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.04	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.1	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.33	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.4866	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	5,239.28	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	184	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	10	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	212	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	14.6	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	79	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	39	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	135	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	18	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	6,100	gallons (storage needed to store a 14 day reagent supply rounded to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0745

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	247.91	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$15,869,985	in 2020 dollars
Reagent Preparation Cost (RPC) =	$2,596,797	in 2020 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2020 dollars
Balance of Plant Costs (BPC) =	$3,991,129	in 2020 dollars
Total Capital Investment (TCI) =	$29,195,285	in 2020 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$15,869,985 in 2020 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$2,596,797 in 2020 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2020 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529{,}000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$3,991,129 in 2020 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$460,702 in 2020 dollars
Indirect Annual Costs (IDAC) =	$2,179,335 in 2020 dollars
Total annual costs (TAC) = DAC + IDAC	$2,640,036 in 2020 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$145,976 in 2020 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$29,176 in 2020 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$92,642 in 2020 dollars
Annual Catalyst Replacement Cost =		$192,907 in 2020 dollars

For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.

Method 1 (for all fuel types):	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	* Calculation Method 1 selected.
Method 2 (for coal-fired industrial boilers):	$(Q_B/NPHR) \times 0.4 \times (CoalF)^{2.9} \times (NRF)^{0.71} \times (CC_{replace}) \times 35.3$	
Direct Annual Cost =		$460,702 in 2020 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$4,286 in 2020 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$2,175,049 in 2020 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$2,179,335 in 2020 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,640,036 per year in 2020 dollars
NOx Removed =	278 tons/year
Cost Effectiveness =	$9,492.57 per ton of NOx removed in 2020 dollars

Attachment 2

Jansen Report for Installation of SNCR on No. 9 Power Boiler

Customized
Engineered
Solutions

JANSEN
Combustion and Boiler
Technologies, Inc.

12025 115th Avenue N.E., Suite 250
Kirkland, WA 98034-6943 U.S.A.
Phone: 425.825.0500
Fax: 425.825.1131
www.jansenboiler.com

Report

to

Sappi Fine Paper North America
Cloquet Plant
Cloquet, Minnesota

Definition Engineering and Class 10 Cost Estimate for the No. 9 Power Boiler SNCR System

Revision 0

JANSEN Project No. 2011-0025

September 2011

Preamble

This report summarizes the definition engineering and Class 10 cost estimate for the addition of a Selective Non-Catalytic Reduction (SNCR) system on the No. 9 Power Boiler at Sappi Fine Paper North America's (Sappi) Cloquet mill in Cloquet, Minnesota.

Respectfully submitted,

Matthew A. Henderson, P.E.
Mechanical Engineer

Edward "Ned" C. Dye, P.E.
Vice President

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A. Project Scope Matrix
B. Preliminary Drawings

1. Introduction

1. Introduction

Sappi Fine Paper North America (Sappi) operates the No. 9 Power Boiler at its mill in Cloquet, Minnesota. It is a VU-40 unit that was supplied by Combustion Engineering (CE) in 1980. The boiler currently fires a combination of waste wood and primary clarifier sludge on a CE traveling grate with natural gas as the auxiliary fuel. It was originally designed to provide 300,000 lb/hr of steam at an outlet pressure of 650 psig and 750°F from pulverized coal or No. 6 oil alone or in combination with waste wood (hog fuel) and primary sludge.

Sappi has contracted Jansen Combustion and Boiler Technologies, Inc. (JANSEN) to upgrade the combustion system to increase the steam generation from grate fuels. The equipment for this upgrade will be installed in October 2011.

Sappi is also interested in installing a Selective Non-Catalytic Reduction (SNCR) system on the No. 9 Power Boiler to reduce NO_x emissions from the unit. Sappi has awarded JANSEN a contract to perform Computational Fluid Dynamics (CFD) modeling for an SNCR system as well as provide the definition engineering for a SNCR system in sufficient detail to provide a +/-10% accuracy cost estimate. This report details the results of the definition engineering scope of work for a SNCR system that meets Sappi's goals for NO_x reduction.

2. Description of the Unit

2. Description of the Unit

The No. 9 Power Boiler was supplied by CE in 1980 and was designed with a MCR steaming capacity of 300,000 lb/hr at 750°F and 650 psig. The unit was originally designed to burn pulverized coal or No. 6 fuel oil alone, or in combination with waste wood on a traveling grate.

The three pulverized coal mills were taken out of service several years ago, and natural gas was added to the fuel mix (burned in the registers labeled “BC” which are the fourth from the top). Currently, the unit is burning waste wood and primary sludge on a traveling grate, with natural gas as auxiliary fuel and No. 2 fuel oil as back-up fuel.

The boiler’s grate-to-roof height is approximately 92 feet. The boiler cross section is 15 feet 11 inches wide and 19 feet 11 inches deep. The unit is equipped with a CE traveling grate, four new style Detroit Stoker pneumatic fuel distributors (October 2011 installation), a JANSEN overfire air (OFA) system (October 2011 installation), single stage superheater, generating bank, economizer (additional section installed in 1994), tubular air heater (TAH), mechanical dust collector (MDC), precipitator, and induced draft (ID) fan. Undergrate air (UGA), OFA, and auxiliary fuel burner air is supplied by the forced draft (FD) fan. Ambient fuel distributor air is supplied by a separate fan. The cinder return lines on the rear wall have been removed and the ports closed off. The air from the FD fan is heated in the TAH. A steam coil air heater (SCAH) upstream of the TAH has been taken out of service and the coils removed.

The boiler is equipped with register type burner windboxes in each corner, while each corner windbox consists of eight vertically divided registers. The air flow to each register compartment can be adjusted or biased by actuated dampers (except the lowest level which is equipped with a hand damper). Two of the registers in each corner (level CC and C which are the second and third from the top) are currently blocked off. All other dampers have physical stops that keep them at least 10% open.

The No. 9 Power Boiler is a back-up incineration location for high volume low concentration (HVLC) non-condensable gases (NCG) and low volume high concentration (LVHC) NCG. The LVHC NCG can be burned through a burner either at the register windbox elevation or on the left side wall near the OFA ports. HVLC NCG can be burned in two dedicated HVLC NCG ports (October 2011 installation), one located on each side wall of the boiler just above the OFA level.

3. CFD Modeling

3. CFD Modeling

The first step in evaluating the means of reducing NO_x emissions from the No. 9 Power Boiler was determined with a CFD model of the boiler. The boiler was modeled up to the centerline of the generating bank, which allowed for evaluation of the fuel delivery, UGA and OFA delivery, the burners, and the subsequent effects on combustion. The model also allowed for post-processing modeling of a SNCR system using 19% aqueous ammonia.

3.1 Cases Evaluated

A design CFD modeling case with the new JANSEN OFA system (**JOFA**) had been run previously. NO_x emissions were modeled for this case, including several configurations of SNCR injection locations.

This case is as described below:

- **JOFA**
  - Steam flow of 300,000 lb/hr
  - Hog fuel flow rate of 103,700 lb/hr (wet)
  - Hog fuel moisture content of 50.2%
  - Sludge flow of 4,500 lb/hr (wet)
  - Sludge moisture content of 58.1%
  - Natural gas of 68,300 scfh
  - Total air flow of 464,100 lb/hr
  - Excess air of 23.6%
  - Upgraded JANSEN OFA system with:
    - Four large-sized (96 in^2 each), high energy, interlaced air nozzles on each side wall at an elevation of approximately 9.5 feet above the grate.
    - 6 of 8 OFA nozzles fully opened, with left-rear and right-front nozzles dampered off.
  - Heat input of 446 million Btu/hr from hog fuel and sludge; 68 million Btu/hr from natural gas.

Additionally, a second case was run with flue gas recirculation (FGR) to the UGA plenum to determine the change in NO_x emissions, with and without SNCR. Since Sappi has informed JANSEN that they are not interested in pursuing a FGR system at this time, this option was not further explored.

3.2 Factors Infusing NO_x Reduction with SNCR

Many factors will influence the effectiveness of a liquid-type SNCR system including:

- The SNCR reagent flow rate.
- Injection locations.

- Droplet diameters of spray.
- Shape of spray.
- Flue gas temperature.
- Flue gas oxygen content.

The temperature plays an important role because of the relative rates of NH_3 oxidation and the rate of NO_x reduction with NH_3. The rates of these two reactions are shown as a function of temperature in Figure 3-1 for typical concentrations of NO_x and ammonia from SNCR. Below approximately 1,350 K, (1,970°F) the rates of reduction are predicted to be higher than the rates of NO_x formation. The actual temperature breakpoint will depend on the concentrations of O_2 and NO_x.

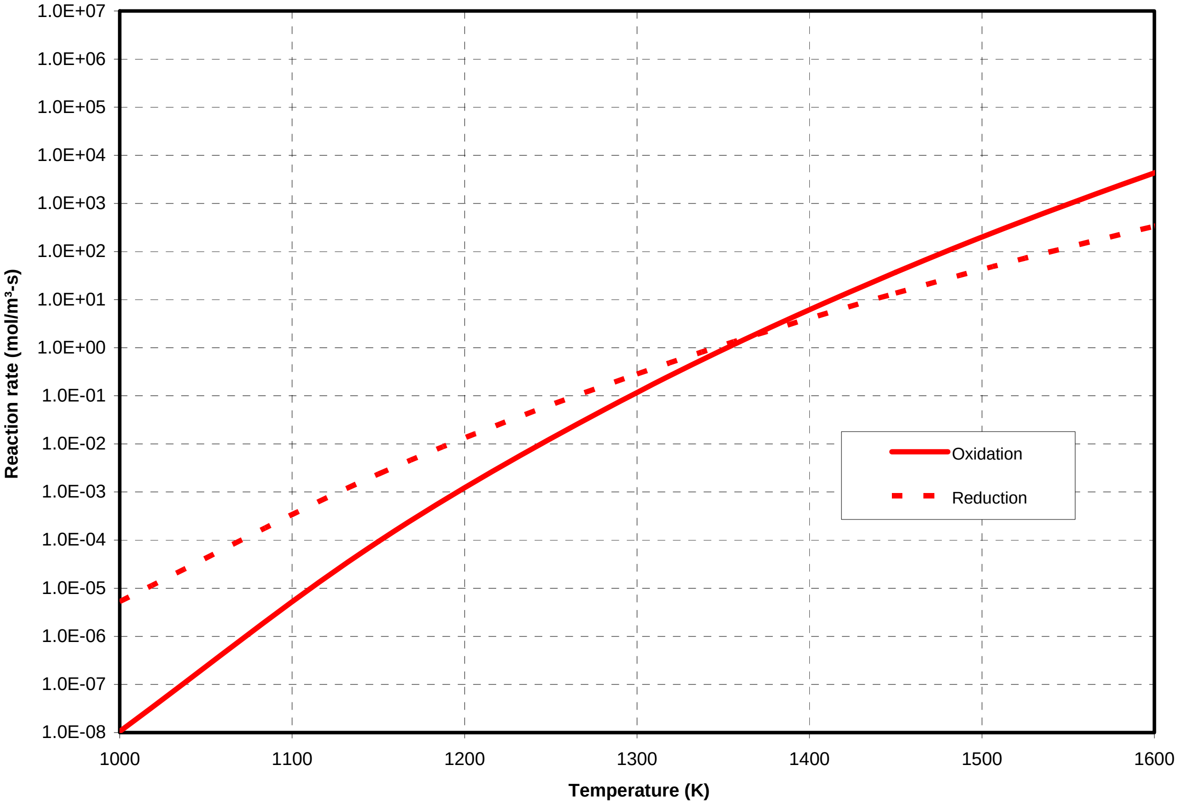


Figure 3-1. Rates of NH_3 Oxidation and Reduction of NO_x as a Function of Temperature

At temperatures nearer the lower end of the scale (e.g., 1,000 K), the rates of NH_3 oxidation become low enough such that residual ammonia concentrations are high enough that ammonia “slip” becomes an issue. This leads to the so called temperature window in which SNCR is viable. Rates for one set of conditions are plotted in Figure 3-2, showing a window of about 1,175 K to 1,275 K (1,660°F to 1,840°F).

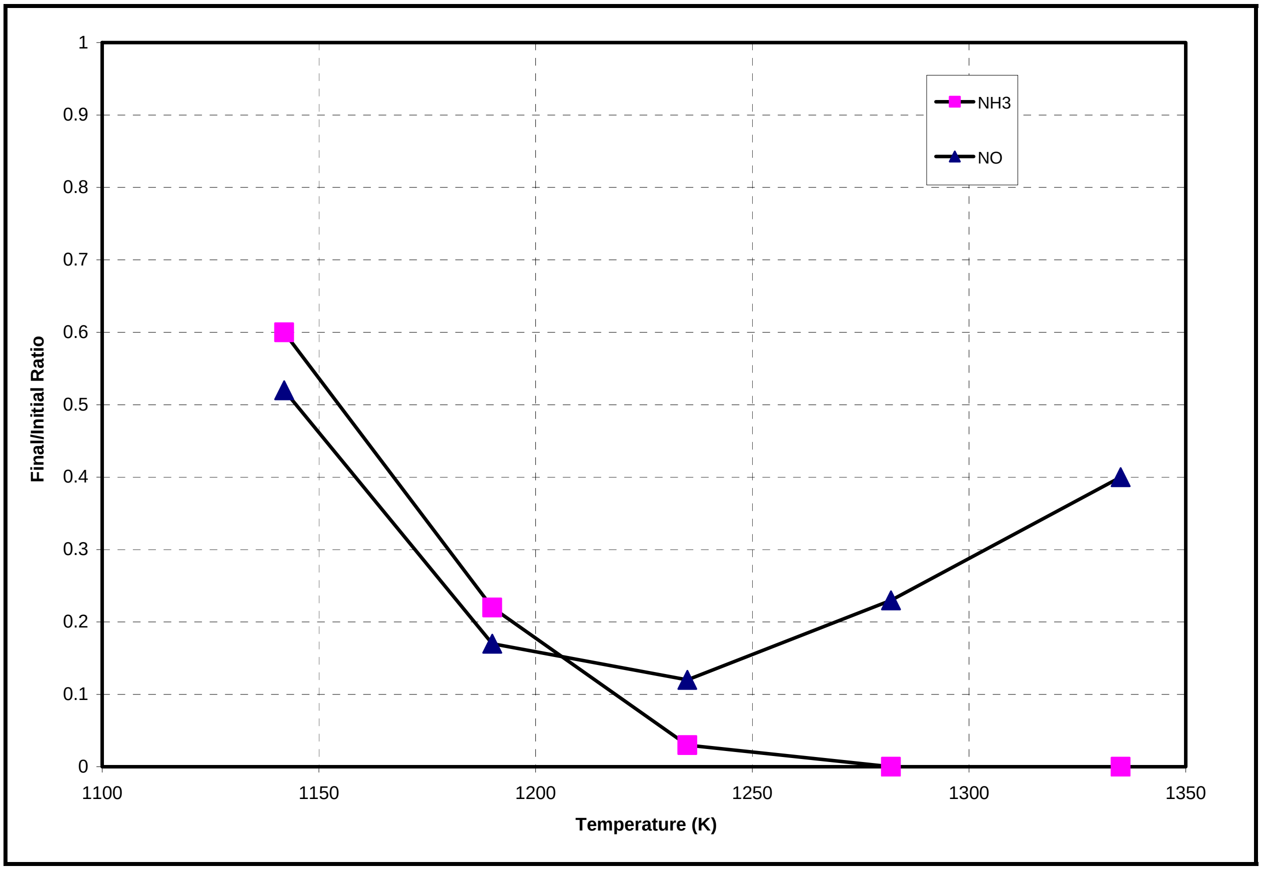


Figure 3-2. Residual NH_3 and NO_x Concentrations as Function of Temperature

Three of the main factors that will influence the effectiveness of SNCR: namely, the flue gas oxygen concentration, the temperature profiles, and the distribution of NO_x in the furnace are shown Figure 3-3. The oxygen plot was generated by coloring the regions in the boiler where the O_2 concentration was less than 4%. Regions colored red or yellow have O_2 concentrations approaching 4%, regions of blue are close to 0% oxygen, and regions where there is no coloring are greater than 4%. (Spraying ammonia into regions of high O_2 may lead to oxidation of the NH_3 to NO_x rather than reducing it. This is more likely if the temperatures are higher or if NO_x concentrations are low.)

Regions of the boiler colored red have temperatures near 1,350 K (1,970°F), near the upper limit for SNCR effectiveness. Much of the lower furnace is above a temperature of 1,350 K (1,970°F). The gases cool down below 1,150 K (1,650°F) as they pass through the superheater.

For the area above the nose arch on the No. 9 Power Boiler, the highest concentrations of NO_x are along the front wall. This is due to the swirl generated at the OFA level. Changes in the set-up of OFA would be expected to lead to differing profiles of NO_x in the upper furnace.

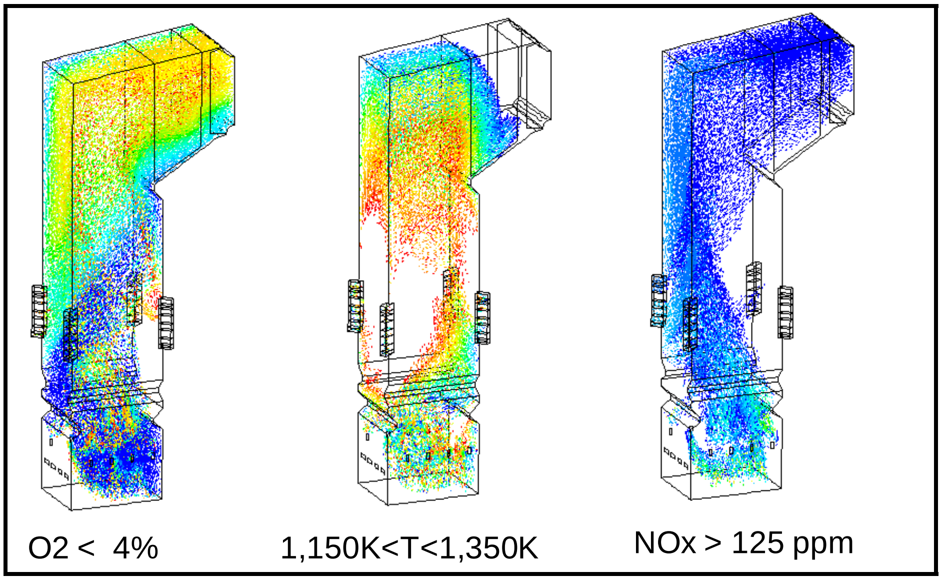


Figure 3-3. Oxygen, Temperature, and NO_x Profiles for the JOFA Case

3.3 SNCR Injection Locations

Using the factors from the previous section, four SNCR injection locations were chosen: two on the front wall and one on each side wall. The side wall injection locations were at an elevation just below the nose arch and the ones on the front wall, above the nose arch. The trajectories of the SNCR reagent droplets are tracked on the left side of Figure 3-4. Essentially all of the droplets have evaporated by a point about 10 feet from the nozzle locations.

The resulting decrease in NO_x is shown on the right side of Figure 3-4. NO_x concentrations of over 175 ppm along the front wall are quickly reduced to the range of 50 ppm by the action of SNCR. Concentrations of NO_x along the right side wall that are initially about 100 ppm are also reduced.

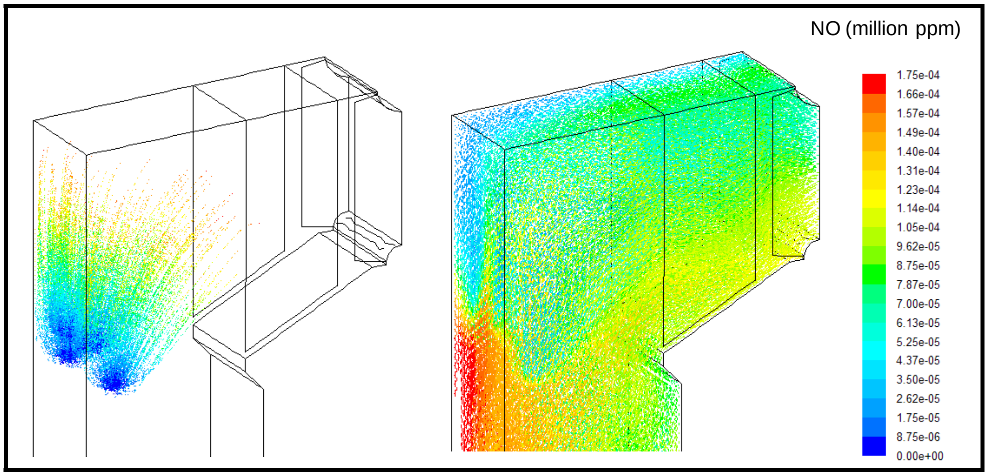


Figure 3-4. SNCR and the Resulting Decrease in NO_x

NO_x concentrations in the upper furnace, with and without SNCR, are shown in Figure 3-5. SNCR is effective in removing much of the NO_x along the front wall, but higher concentrations of NO_x persist in the lower sections of the superheater and generating bank. This NO_x originates from the gases along the front wall that swirl up the right side wall into the convective sections. Reducing this pocket of NO_x is more difficult because it requires injecting the reagent lower in the furnace, where the temperatures are higher and the effectiveness is less.

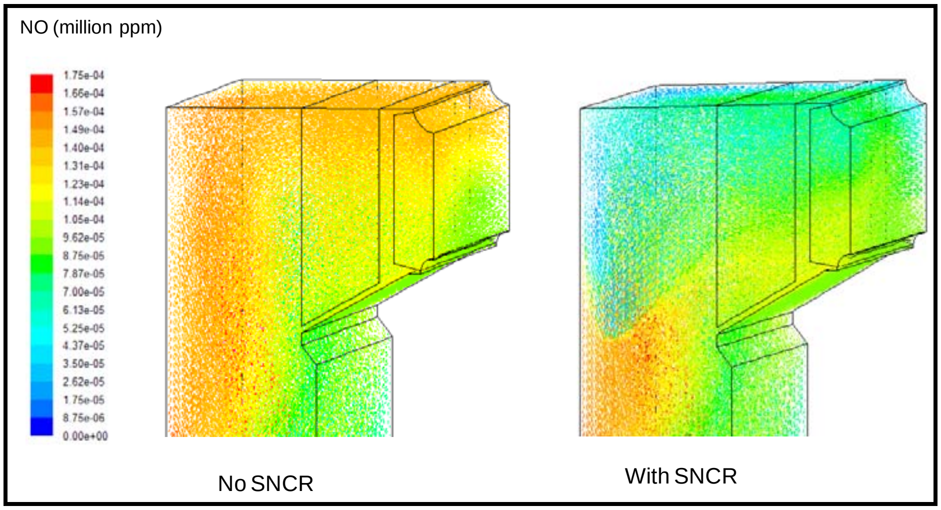


Figure 3-5. NO_x Concentrations With and Without SNCR

3.4 Results of SNCR System

The reagent used for this SNCR system is 19% aqueous ammonia. This would be sprayed into the upper furnace through four (4) wall nozzles.

Without an SNCR system, the predicted NO_x emissions were 0.22 lb/million Btu. With the addition of an SNCR system, the emissions were reduced to less than 0.18 lb/million Btu with a flow rate of 35 gallons per hour, and were further reduced down to 0.16 lb/million Btu with a flow rate of 88 gallons per hour. The rate of NO_x reduction diminishes with increased aqueous ammonia flow rates; however, the ammonia slip also increases. Ammonia slip was predicted to be moderate for the 88 gallons per hour case at approximately 1 ppm.

One alternative SNCR system arrangement that was investigated utilized three levels of aqueous ammonia injection stacked on the right side wall. This arrangement achieved NO_x emissions of less than 0.15 lb/million Btu at an aqueous ammonia flow rate of 83 gallons per hour. However, this case resulted in 16 ppm of ammonia slip, which is likely excessive.

No SNCR arrangements were found that could reduce NO_x emissions to less than 0.12 lb/million Btu, but reductions in the range of 25% to 30% are feasible.

A memo titled “CFD Model of the Sappi Cloquet No. 9 Power Boiler” detailing the entire CFD process and results was submitted to Sappi on July 28, 2011.

4. SNCR System

4. SNCR System Equipment Description and Scope of Supply

4.1 SNCR System

The new SNCR system will be custom designed for the requirements for the No. 9 Power Boiler. The design criteria for the SNCR system was based on an aqueous ammonia flow rate of 88 gallons per hours as established through the use of CFD modeling of the No. 9 Power Boiler.

The following describes the equipment and scope of supply for the SNCR system. A list of new equipment needed for the SNCR upgrade, noting the source of supply, can be found in the *Project Scope Matrix* in Appendix A. Also, refer to Appendix B for the preliminary flow diagrams, arrangement drawings, and equipment drawings for the SNCR system. JANSEN has teamed with Chemithon in the preparation of the equipment design and pricing for the SNCR system.

4.1.1 Aqueous Ammonia Truck Unloading System

The truck unloading system consists of a fabricated steel rack with piping, hose connection fittings, and valves as required for unloading aqueous ammonia from a tanker truck into the storage tank. The unloading system will also have connections to allow the unloading system to be purged with nitrogen once unloading is complete. The unloading system will be located outside adjacent to the aqueous ammonia storage tank.

4.1.2 Nitrogen Purge System

A nitrogen purge system consisting of a bottle rack, regulator valves, and pressure gauge will be included. The nitrogen purge system will be used to purge the truck unloading system once the unloading operation is complete as well as provide a nitrogen blanket for the aqueous ammonia storage tank.

4.1.3 Aqueous Ammonia Storage Tank

The aqueous ammonia storage tank is a horizontal, 15,000 gallon, carbon steel, ASME Section VIII vessel designed for 30 psig. The tank will be equipped with inlet and outlet shutoff valves, safety relief valves, level transmitter, pressure transmitter, pressure gauge, and nitrogen purge connection with a pressure regulator. The storage tank will be located outside the No. 9 Power Boiler building on the east side of the building under the pipe rack. Piping from the aqueous ammonia storage tank will be routed to the aqueous ammonia pump system.

4.1.4 Aqueous Ammonia Pump System

The aqueous ammonia pump system will be located inside No. 9 Power Boiler building on the ground floor at the northeast corner of building. The pump system will take suction from the aqueous ammonia storage tank and supply a constant pressure flow to the aqueous ammonia/dilution water metering system located at elevation 179’-1”.

The aqueous ammonia pump system consists of two (2) 100% capacity ammonia supply pumps mounted on a structural steel skid complete with electric motors, automatic inlet shutoff valves, suction strainers, a discharge pressure transmitter, and a discharge pressure control valve that re-circulates back to the aqueous ammonia storage tank.

4.1.5 Dilution Water Pump System

The dilution water pump system will be located inside No. 9 Power Boiler building at elevation 179'-1" in the northwest corner of building. The pump system will be supplied with a utility water flow rate of 2 gallons per minute and supply a constant pressure flow to the aqueous ammonia/dilution water metering system.

The dilution water pump system consists of two (2) 100% capacity dilution water supply pumps mounted on a structural steel skid complete with electric motors, actuated inlet shutoff valves, suction strainers, a discharge pressure transmitter, and a discharge pressure regulator to re-circulate water back to the inlet of the pumps.

4.1.6 Aqueous Ammonia/Dilution Water Metering System

Aqueous ammonia and dilution water will be supplied to the aqueous ammonia/dilution water metering system from their respective pump systems. The metering system has two (2) systems for metering and mixing aqueous ammonia and dilution water to supply the aqueous ammonia injection system. This will allow for different concentrations of ammonia to be supplied to the side wall injection points and the front wall injection points. The aqueous ammonia/dilution water metering system will be located inside No. 9 Power Boiler building at elevation 179'-1" in the northwest corner of building.

A structural steel skid will make up the base of the aqueous ammonia/dilution water metering system. Mounted on the skid will be a piping system composed of two (2) aqueous ammonia flow meters, two (2) dilution water flow meters, two (2) aqueous ammonia flow control valves, and two (2) dilution water flow control valves. Also included are two (2) actuated discharge valves and pressure gauges.

4.1.7 Cooling Air Supply System

Cooling air for the aqueous ammonia injectors will be provided by the cooling air supply system. The cooling air supply system will be located inside No. 9 Power Boiler building at elevation 179'-1" in the northwest corner of building. New floor steel (by others) will be installed to mount the skid.

The cooling air supply system skid will be made up of two (2) 100% capacity blowers with electric motors and automatic discharge isolation valves. The blowers, valves and piping will be mounted on a structural steel frame.

4.1.8 Aqueous Ammonia Injection System

The aqueous ammonia injection system will be located inside the No. 9 Power Boiler building at elevation 179'-1" on the west side of the building just in front of the boiler. The aqueous ammonia injection system is a rack mounted manifold system that will be fed by the aqueous ammonia/dilution water metering system and the cooling air supply system. A mill air supply (by others) will also be required. These three streams will be monitored and adjusted with the aqueous ammonia injection system prior to feeding the four (4) injection points on the boiler.

4.1.9 Aqueous Ammonia Injectors

Four (4) aqueous ammonia injectors will be installed on the No. 9 Power boiler. Two (2) will be installed on the front wall of the boiler just above the elevation of the rear nose arch and one (1) will be installed on each side wall just below the elevation of the nose arch. Each injector will be supplied with aqueous ammonia, mill air for atomization, and cooling air from the aqueous ammonia injection system. A new single tube bend open will required for each injector. A seal box with mounting flange will be provided for each injector.

4.2 Pressure Parts

Four (4) new single tube bend opening will be required for the aqueous ammonia injectors and have been included in this cost estimate. The tubing material will match or exceed the existing tubing material design.

4.3 Piping

Most of the piping between the various pieces of SNCR equipment will be small bore piping that will be field routed by the installing contractor. In the few instances where large bore piping is required, the design for the piping layout has been included in the cost estimate. For the purpose of the +/- 10% cost estimate, the installation contractor has included the cost of piping material in their estimate.

4.4 Structural

In general, any modifications or additions to existing building steel have not been included in the scope.

New building steel will be required to extend the floor to support the cooling air supply system at elevation 179’-1”. The new platform will be located at the northwest corner of the building. The engineering and design of this platform has been included. The material supply and installation will be by others and have not been included in this estimate.

4.5 Foundations

The aqueous ammonia storage tank will require a new foundation with a containment wall. The engineering and design for this foundation has been included in the cost estimate. It will be approximately 45 feet long and 15 feet wide with a 4 foot containment wall. The materials for the foundation and wall, as well as the installation, will be by others and have not been included in this cost estimate.

4.6 Electrical, Instrumentation and Controls

The supply of the field instruments and motors for the SNCR system has been included in the scope of the cost estimate and will be wired to skid mounted junction boxes for the individual pieces of equipment.

A PLC control panel that will be remote mounted in the control room or a local MCC room is also included.

Instrument cabling to and from the skids, power cabling to and from the skids, MCC modifications, and DCS modifications, as required for the new SNCR system, have not been included in the scope of the cost estimate.

4.7 Insulation and Heat Tracing

Insulation and heat tracing of the equipment has not been included, and with the possible exception of the aqueous ammonia storage tank, is not required. Insulation, lagging, and refractory for the boiler walls at the locations of the injection points has been included.

4.8 Engineering Services

In addition to the detailed mechanical design of the systems described in the preceding sections, additional engineering services have been included in the JANSEN scope of supply. These services included in the cost estimate are:

- Project management and sub-contractor interface.
- Computer-aided design and drafting using AutoCAD, providing ducting fabrication assembly drawings as well as a detailed installation drawing package.
- Site visits to gather dimensional information and verify new system interface points.
- Operator training including training materials.
- Construction observation and on-site engineering support.
- Start-up assistance to provide support to operators in tuning the boiler's new systems.

4.9 Relocations

The relocation of any existing equipment, piping, instruments, or electrical cabling has not been included in this cost estimate. Also excluded from this cost estimate is the relocation of any underground piping, cabling, or sewers that may need to be relocated for the installation of the aqueous ammonia storage tank foundation.

4.10 Installation

The installation of the SNCR system has been included in JANSEN's scope of supply. The installation contractor will be responsible for and will coordinate any additional sub-contractors as necessary to complete the installation of the upgrades previously discussed. The activities and services provided by the installation contractor will include:

- Mobilization.
- Labor for installation.
- Equipment rental including cranes and compressors.
- Small tools and consumables.
- Scaffolding.
- Insulation and lagging removal and installation.

- Refractory removal and installation.
- Safety training and personnel.
- Quality assurance and testing.
- Clean-up and demobilization.

5. Project Cost Estimate

5. Project Cost Estimate

5.1 General

The overall scope of the cost estimate is as described in Section 4 above. A line item summary of the major work items involved is found in Appendix A, *Project Scope Matrix.*

The equipment supply and fabrication cost estimates in this report have been based on cost information from suppliers specifically for this project, or data on file from previous projects.

5.2 Scope of Cost Estimates

The intended scope of the cost estimate for the equipment is only for the items within the JANSEN scope of supply as defined in Appendix A, *Project Scope Matrix*. Only those items that are within the Sappi scope of supply are excluded from this cost estimate.

The major types of items included in the cost estimate are:

- New equipment supply.
- Modifications to existing equipment, if required.
- Field mounted instrumentation and motor supply.
- Engineering, design, and drawings for the final phase of the project.

The preliminary drawings in Appendix B also provide definition of the scope of new work, and indicate areas of work provided by Sappi, and areas provided by this report’s scope.

5.3 Items Not Included in the Cost Estimate

Certain items that may be required as part of the overall upgrade project have been excluded from the scope of preliminary engineering, are provided by others, or are otherwise not included as a part of this cost estimate.

Items not covered by this estimate include:

- Instrument air supply to equipment.
- Electrical and signal control cabling material supply.
- Instrumentation pneumatic tubing material supply.
- Structural engineering and material supply.
- Foundation material supply.
- Boiler chemical cleaning, if required.
- Taxes, fees, or permit costs.
- Sappi project engineering, administration, or other project indirect costs.
- Hazardous material testing, abatement of disposal.

- Heat tracing and insulation.
- Repairs of existing equipment unless specifically addressed in this report.

5.4 Project Schedule

It is estimated the project schedule will require 9-10 months from release of a purchase order by Sappi to provide final engineering, construction installation drawings, and delivery of the equipment on-site in Cloquet, Minnesota.

Since most of the equipment can be installed prior to shutting the boiler down, construction outage time for an upgrade of this nature is expected to require approximately 5-7 days from release of the clean boiler to when it is returned back to Sappi.

5.5 Cost Estimate (+/- 10%)

A detailed line listing of the items included in the scope of the cost estimate is found in Appendix A, *Project Scope Matrix*.

The +/-10% cost estimate is as follows:

CFD Model and Process Evaluation:	Completed
Equipment Engineering and Supply for: • SNCR System	$1,484,000
Installation of: • SNCR System	$248,860
Total Project Cost:	$1,732,860

The cost estimate has been compiled from several sources and contains current pricing information for the project equipment and services as of the date of this report. The cost estimate may need to be revised or updated based on future final project approval dates.

It is assumed the installation contractor will be contracted directly by Sappi. The installation estimate listed above is as received from the installation contractor and does not include any provisions for mark-up or contingency, other than what may have been included by the contractor.

The cost estimate is exclusive of any present or future federal, state/provincial, municipal, or other sales, property, excise or use taxes with respect to the material, equipment, or services covered hereby.

JANSEN
Combustion and Boiler
Technologies, Inc.

Appendix A

Project Scope Matrix

PROJECT SCOPE MATRIX
Sappi Fine Paper North America - Cloquet, Minnesota
No. 9 Power Boiler SNCR Upgrade - EPC Proposal Cost Estimate

JANSEN
Combustion and Boiler Technologies, Inc.

Jansen Project No. 2011-0025

Created by: MAH

Date Created: August 19, 2011
Revision Date: September 28, 2011
Revision No.: 1

PROJECT SCOPE MATRIX

No.	CATEGORY DESCRIPTION	Engineered By:	Materials By:	Installation By:	Quantity	Revision
1.0	**SNCR UPGRADE**					
1.1	**DEMOLITION FOR SNCR UPGRADE**					
A	Remove boiler casing and insulation at new SNCR injection port locations, front, left & rt walls	JANSEN	Contractor	Contractor	4	
1.2	**MECHANICAL SYSTEM WORK FOR SNCR SYSTEM**					
1.2.1	**Aqueous Ammonia Truck Unloading System**					
A	Rack mounted unloading system complete with piping and valves	JANSEN	JANSEN	Contractor	1	
1.2.2	**Nitrogen Purge System**					
A	Bottle rack, valves, pressure regulator and pressure indicator	JANSEN	JANSEN	Contractor	1	
B	Nitrogen bottles	-	Sappi	Sappi	3	
1.2.3	**Aqueous Ammonia Storage Tank**					
A	15,000 gallon, carbon steel, 30 psig design, 9 ft diameter x 30 ft length	JANSEN	JANSEN	Contractor	1	
B	Pressure safety valve	JANSEN	JANSEN	Contractor	2	
C	Level transmitter	JANSEN	JANSEN	Contractor	1	
D	Automated block valve	JANSEN	JANSEN	Contractor	3	
E	Pressure transmitter	JANSEN	JANSEN	Contractor	1	
F	Pressure indicator	JANSEN	JANSEN	Contractor	1	
G	Ammonia monitor	JANSEN	JANSEN	Contractor	4	
H	Nitrogen blanketing system	JANSEN	JANSEN	Contractor	1	
1.2.4	**Aqueous Ammonia Pump System**					
A	Structural steel skid	JANSEN	JANSEN	Contractor	1	
B	Ammonia supply pump with 0.5 hp motor	JANSEN	JANSEN	Contractor	2	
C	Automated block valve	JANSEN	JANSEN	Contractor	2	
D	Backpressure regulating valve	JANSEN	JANSEN	Contractor	1	
E	Suction strainers	JANSEN	JANSEN	Contractor	2	
F	Pressure transmitter	JANSEN	JANSEN	Contractor	1	
G	Pressure indicator	JANSEN	JANSEN	Contractor	2	
1.2.5	**Dilution Water Pump System**					
A	Structural steel skid	JANSEN	JANSEN	Contractor	1	
B	Dilution water supply pump with 0.5 hp motor	JANSEN	JANSEN	Contractor	2	
C	Automated block valve	JANSEN	JANSEN	Contractor	2	
D	Backpressure regulating valve	JANSEN	JANSEN	Contractor	1	
E	Suction strainers	JANSEN	JANSEN	Contractor	2	
F	Pressure transmitter	JANSEN	JANSEN	Contractor	1	
G	Pressure indicator	JANSEN	JANSEN	Contractor	2	
1.2.6	**Aqueous Ammonia/Dilution Water Metering System**					
A	Structural steel skid	JANSEN	JANSEN	Contractor	1	
B	Automated block valve	JANSEN	JANSEN	Contractor	2	
C	Flow control valve	JANSEN	JANSEN	Contractor	4	
D	Flow elements	JANSEN	JANSEN	Contractor	4	
E	Pressure indicator	JANSEN	JANSEN	Contractor	2	
1.2.7	**Cooling Air Supply System**					
A	Structural steel skid	JANSEN	JANSEN	Contractor	1	
B	Cooling air blowers with 7.5 hp motor	JANSEN	JANSEN	Contractor	2	
C	Automated block valve	JANSEN	JANSEN	Contractor	2	
D	Pressure indicator	JANSEN	JANSEN	Contractor	2	
1.2.8	**Aqueous Ammonia Injection System**					
A	Structural steel skid	JANSEN	JANSEN	Contractor	1	
B	Pressure regulator	JANSEN	JANSEN	Contractor	1	
C	Pressure switch	JANSEN	JANSEN	Contractor	2	
D	Flow elements	JANSEN	JANSEN	Contractor	8	
E	Pressure indicator	JANSEN	JANSEN	Contractor	2	
1.2.9	**Aqueous Ammonia Injector**					
A	Injector	JANSEN	JANSEN	Contractor	4	
B	Seal box	JANSEN	JANSEN	Contractor	4	
C	Flex hoses	JANSEN	JANSEN	Contractor	12	
1.2.10	**Piping Work**					
A	Small bore field route piping between SNCR equipment skids	JANSEN	Contractor	Contractor	4	
B	Large bore piping between SNCR equipment skid	JANSEN	Contractor	Contractor	1	
C	Instrument air supply to SNCR equipment skids	Contractor	Contractor	Contractor	6	
D	Service water to dilution water pump system	Contractor	Contractor	Contractor	1	
E	Relocaiton of existing above ground or below ground piping	Sappi	Sappi	Sappi	1	

PROJECT SCOPE MATRIX
Sappi Fine Paper North America - Cloquet, Minnesota
No. 9 Power Boiler SNCR Upgrade - EPC Proposal Cost Estimate

Jansen Project No. 2011-0025

Created by: MAH

JANSEN
Combustion and Boiler Technologies, Inc.

Date Created: August 19, 2011
Revision Date: September 28, 2011
Revision No.: 1

PROJECT SCOPE MATRIX

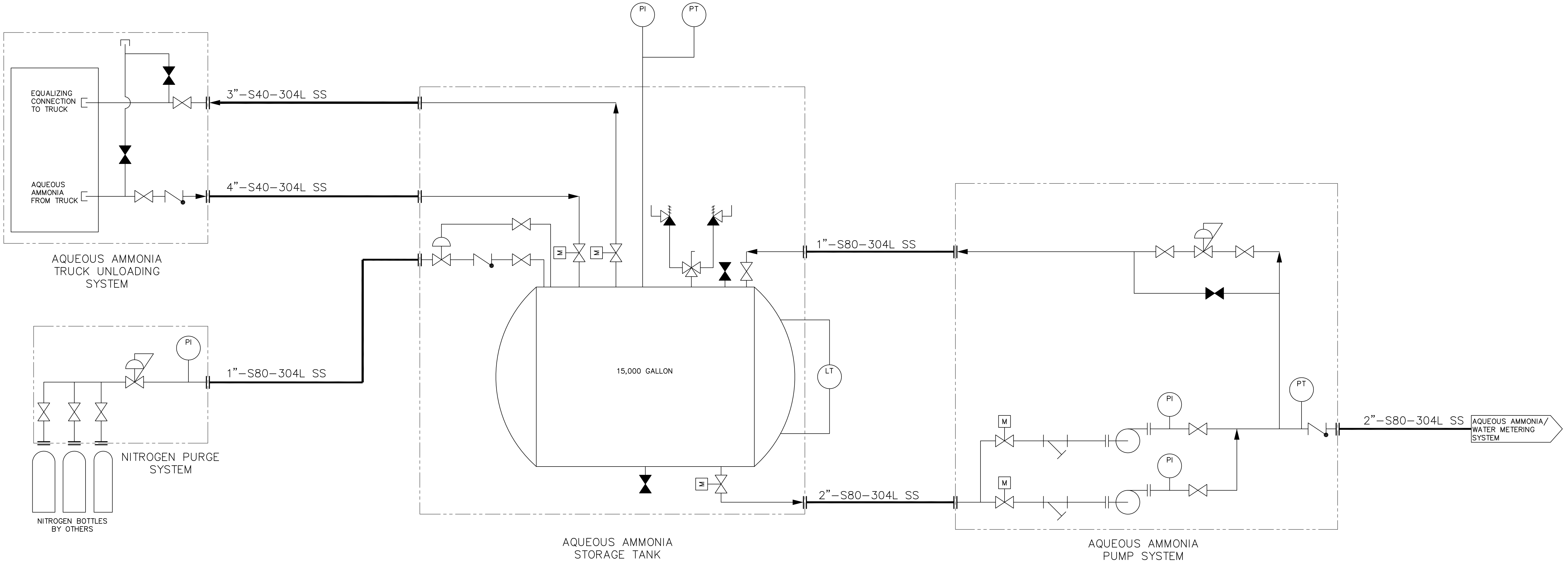
No.	CATEGORY DESCRIPTION	Engineered By:	Materials By:	Installation By:	Quantity	Revision
1.2.11	**Pressure Part Work**					
A	New front wall and sidewall bent tube sections for injector openings	JANSEN	JANSEN	Contractor	4	
B	Radiography of pressure welds	-	Contractor	Contractor	1	
1.3	**CILVIL / STRUCTURAL WORK FOR SNCR SYSTEM**					
A	Aqueous ammonia storage tank foundation and containment wall	JANSEN	Sappi	Sappi	1	
B	Aqueous ammonia pump system pad	JANSEN	Sappi	Sappi	1	
C	Dilution water pump system pad	JANSEN	Sappi	Sappi	1	
D	Aqueous ammonia/water metering system pad	JANSEN	Sappi	Sappi	1	
E	Cooling air supply system pad	JANSEN	Sappi	Sappi	1	
F	Aqueous ammonia injection system pad	JANSEN	Sappi	Sappi	1	
G	Steel to extend floor at 179'-1"	JANSEN	Sappi	Sappi	1	
1.4	**ELECTRICAL / INSTRUMENTS & CONTROLS FOR SNCR SYSTEM**					
A	SNCR system PLC control panel to be located in control room	JANSEN	Sappi	Sappi	1	
B	Power and instrument cabling to aqueous ammonia storage tank	Sappi	Sappi	Sappi	1	
C	Power and instrument cabling to aqueous ammonia pump system	Sappi	Sappi	Sappi	1	
D	Power and instrument cabling to dilution water pump system	Sappi	Sappi	Sappi	1	
E	Power and instrument cabling to aqueous ammonia/water metering system	Sappi	Sappi	Sappi	1	
F	Power and instrument cabling to cooling air supply system	Sappi	Sappi	Sappi	1	
G	Power and instrument cabling to aqueous ammonia injection system	Sappi	Sappi	Sappi	1	
H	DCS modifications for new controls	Sappi	Sappi	Sappi	1	
1.5	**INSULATION AND REFRACTORY WORK FOR SNCR SYSTEM**					
A	Install refractory, insulation and lagging on boiler walls at new injector locations	JANSEN	Contractor	Contractor	4	
B	Insulation, lagging, and heat tracing for aqueous ammonia storage tank	Sappi	Sappi	Sappi	1	
1.6	**EQUIPMENT VENDOR FIELD SUPERVISION FOR SNCR SYSTEM**					
A	SNCR equipment representative	JANSEN	JANSEN	JANSEN	1	
1.7	**DESIGN ENGINEERING FOR SNCR SYSTEM**					
A	Mechanical Engineering	JANSEN	JANSEN	JANSEN	1	
B	Structural Engineering	Sappi	Sappi	Sappi	1	
C	Construction services, training, and start-up	JANSEN	JANSEN	JANSEN	1	
D	Electrical & Controls Engineering	Sappi	Sappi	Sappi	1	
1.8	**INSTALLATION OF SNCR SYSTEM**					
A	Installation of SNCR System	JANSEN	Contractor	Contractor	1	
B	Hydrostatic test (Boiler)	Contractor	Contractor	Contractor	1	
2.0	**MOBILIZATION, DEMOBILIZATION, and CLEANUP**					
A	Construction Consumables	Contractor	Contractor	Contractor	0	
B	Trailers, Safety, Sanitation, Trash Removal, etc.	Contractor	Contractor	Contractor	0	
C	Safety training	Contractor	Contractor	Contractor	0	
D	Telephone lines	Contractor	Contractor	Contractor	0	
E	Boiler cleaning, washing	Sappi	Sappi	Sappi	0	
F	Scaffolding	Contractor	Contractor	Contractor	0	
G	Compressed air	Contractor	Contractor	Contractor	0	
H	Lockout, environmental safety ("sniffing")	Contractor	Contractor	Contractor	0	
I	Environmental safety (hole-watch, etc.)	Contractor	Contractor	Contractor	0	
J	Equipment Rentals, Cranes, etc.	Contractor	Contractor	Contractor	0	
K	Finish or touch-up painting of structural steel, equipment, etc. per Mill standards	Contractor	Contractor	Contractor	0	
L	Quality Assurance and Testing	Contractor	Contractor	Contractor	0	
M	Miscellaneous	Contractor	Contractor	Contractor	0	
N	Cleanup	Contractor	Contractor	Contractor	0	
O	Demobilize	Contractor	Contractor	Contractor	0	

NOTES:

1 Hazardous material testing or removal is not included.
2 Taxes, fees, import duties, permits or license costs are not included.
3 Sappi project engineering, administrative, etc. costs are not included.
4 Spare parts are not included.
5 Electrical and Instrumentation install materials and costs by Sappi.
6 "Contractor" denotes Jamar performing indicated scope of work under direct contract to Sappi.

Appendix B

Preliminary Drawings



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NO. 9 POWER BOILER SNCR
SNCR SYSTEM
FLOW DIAGRAM

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DWG No. 2011–0025–D– PF-1
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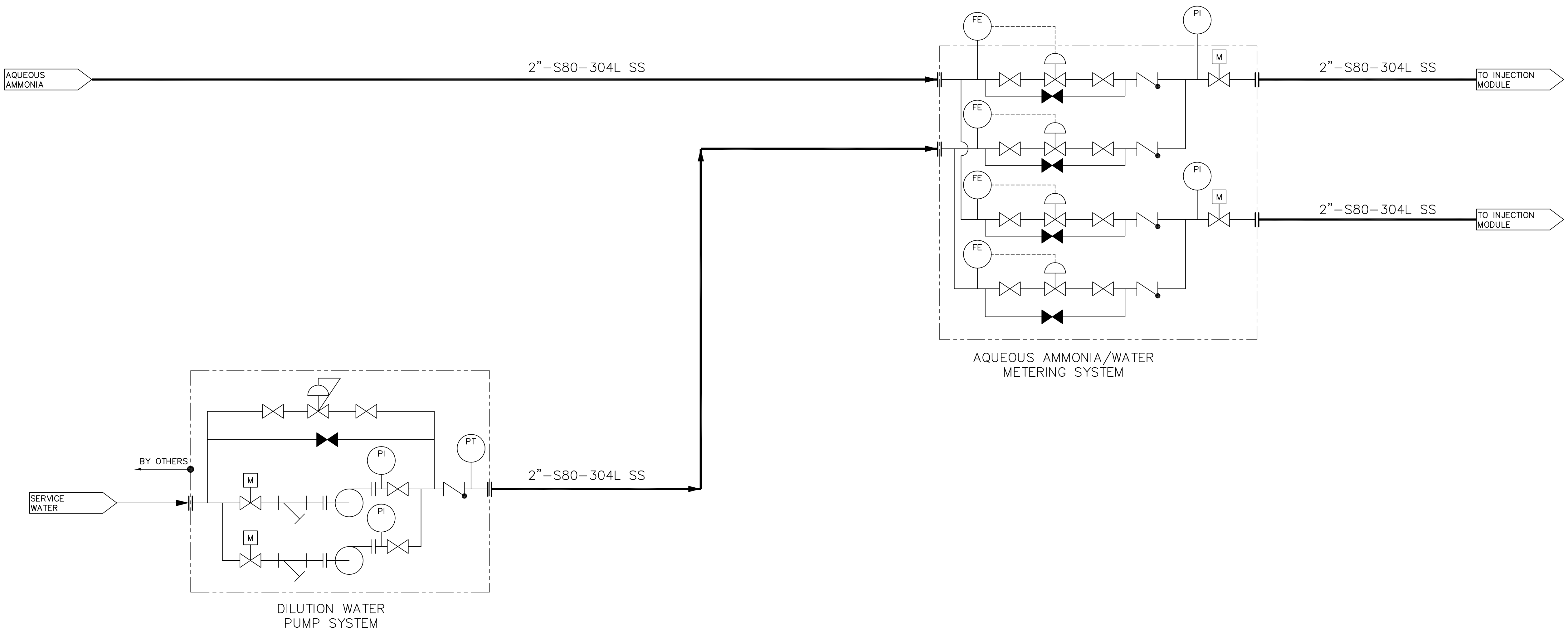

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NO. 9 POWER BOILER SNCR
SNCR SYSTEM
FLOW DIAGRAM

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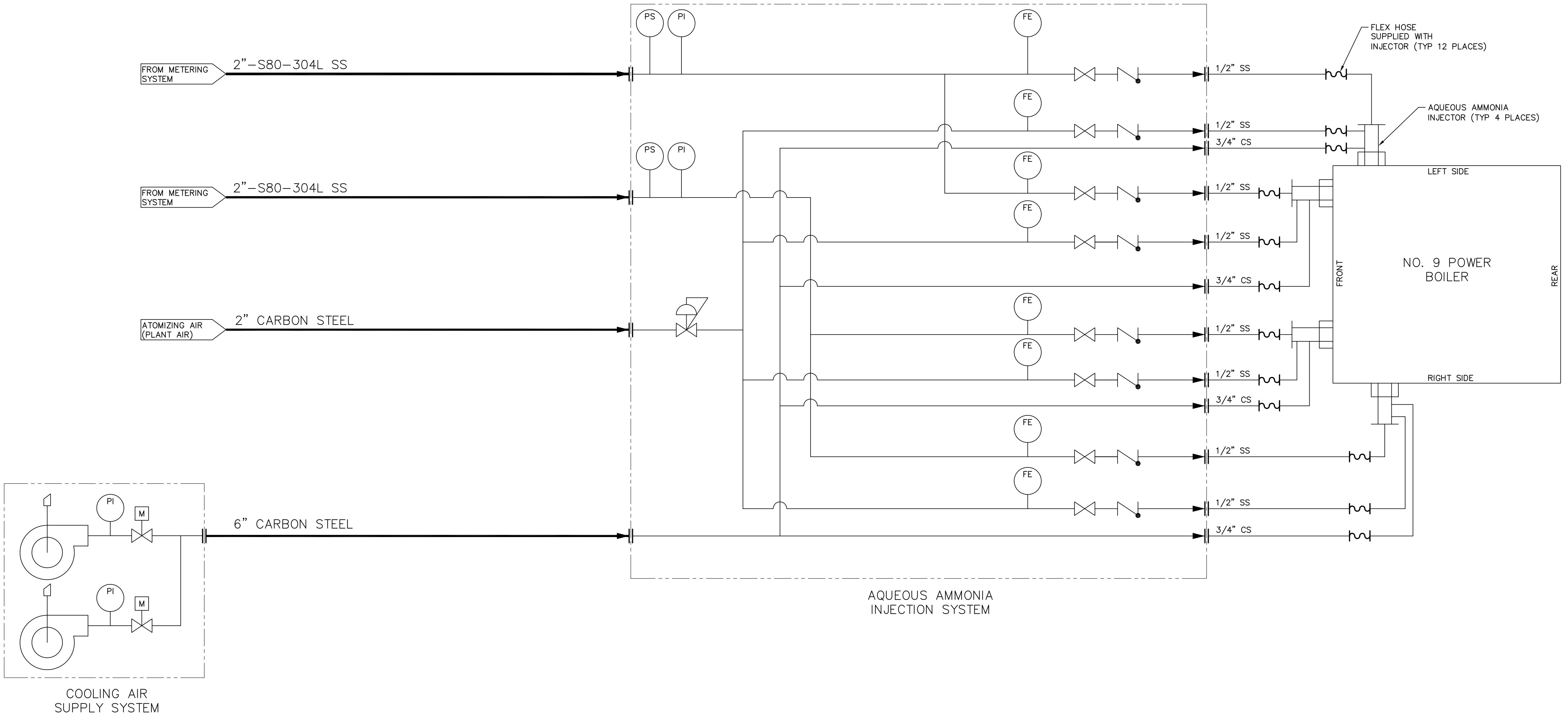

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NO. 9 POWER BOILER SNCR
SNCR SYSTEM
FLOW DIAGRAM

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NO. 9 POWER BOILER SNCR
SNCR INJECTION PORT
ELEVATION VIEW

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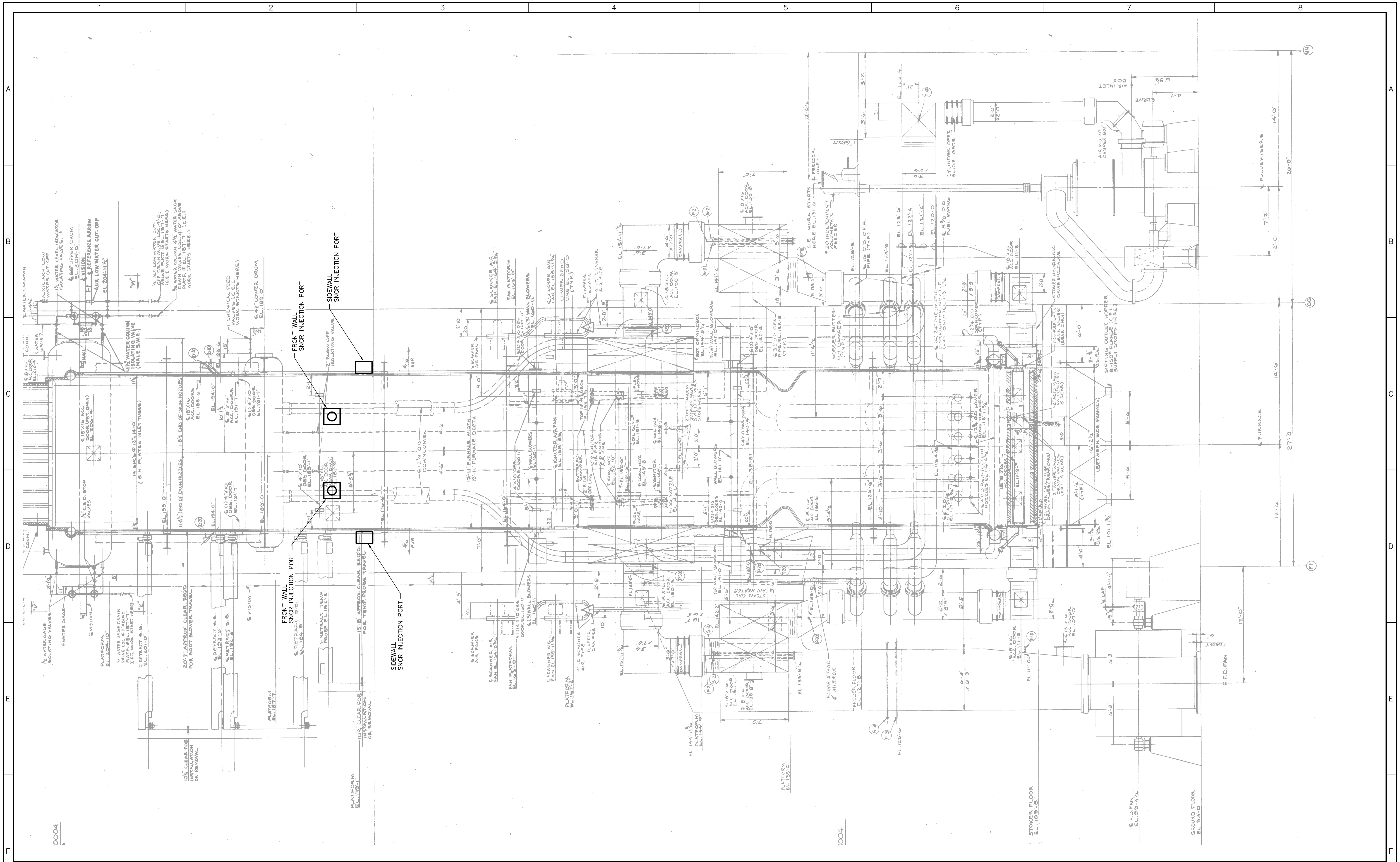

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NO. 9 POWER BOILER SNCR

SNCR INJECTION PORT
ELEVATION VIEW

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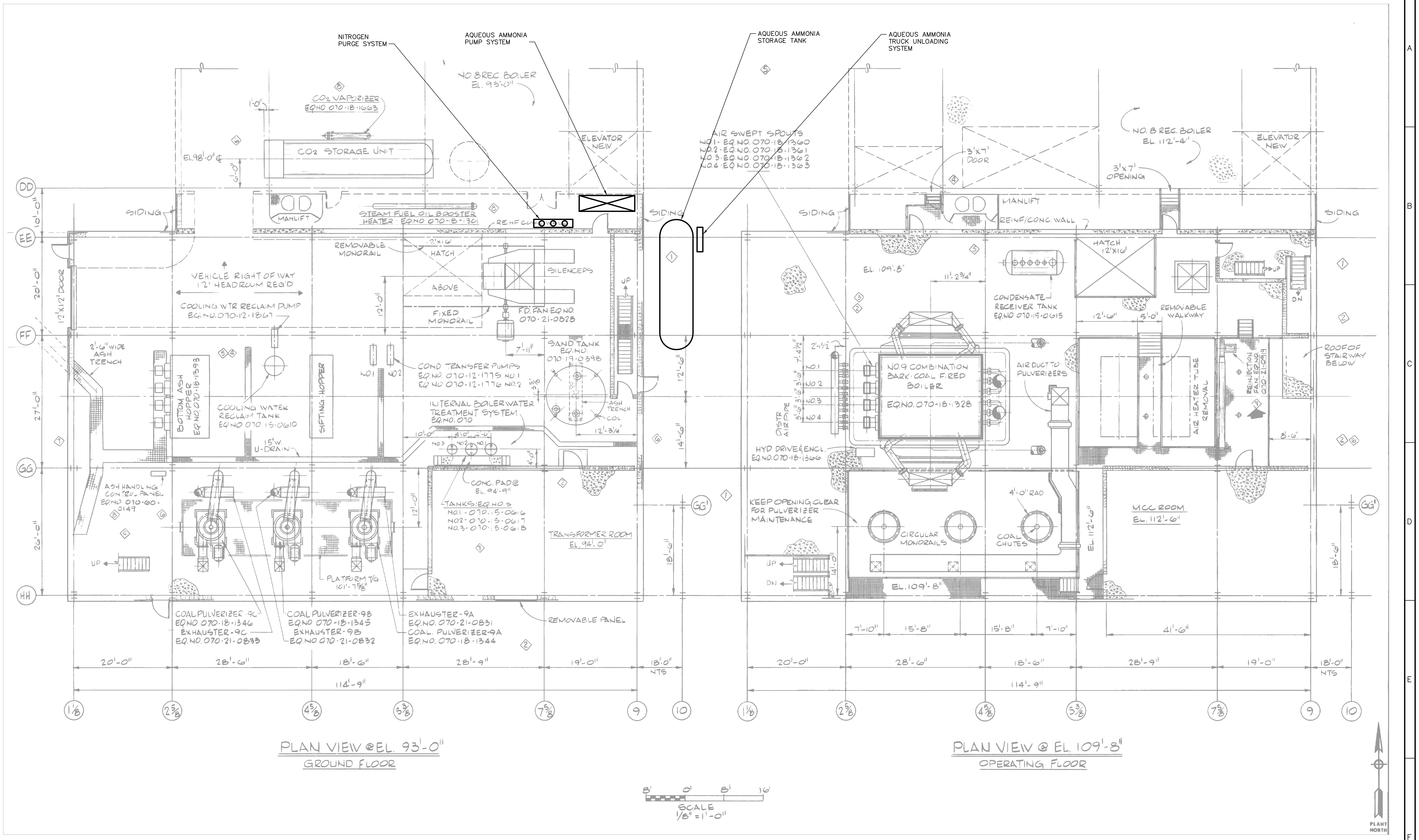

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NO. 9 POWER BOILER SNCR
AMMONIA STORAGE TANK
PLAN VIEW

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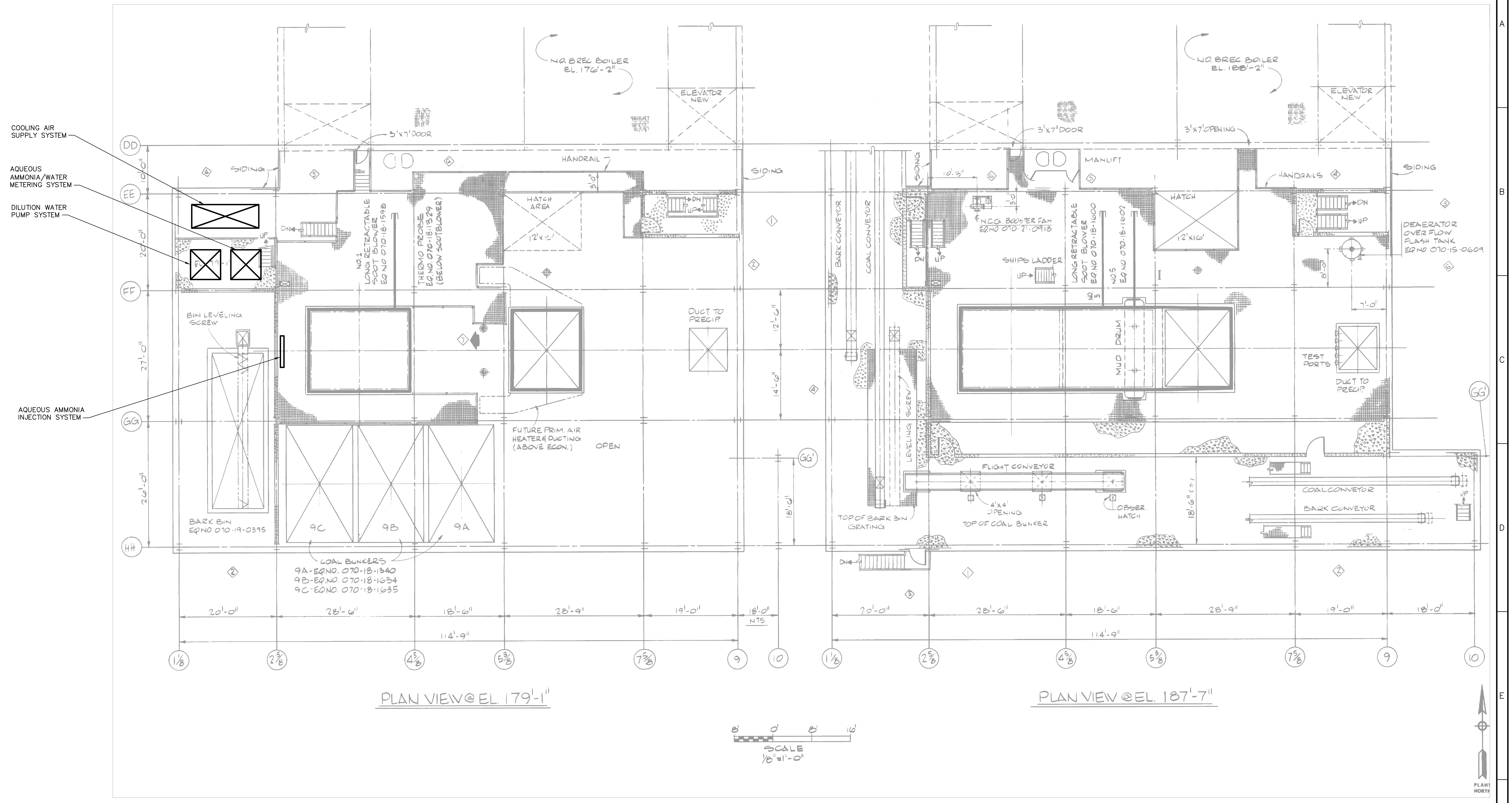

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NO. 9 POWER BOILER SNCR
AQUEOUS AMMONIA INJECTION SYSTEM
PLAN VIEW

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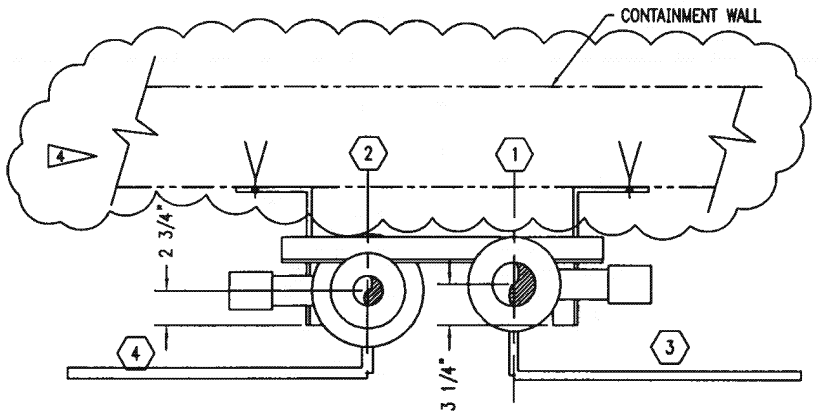
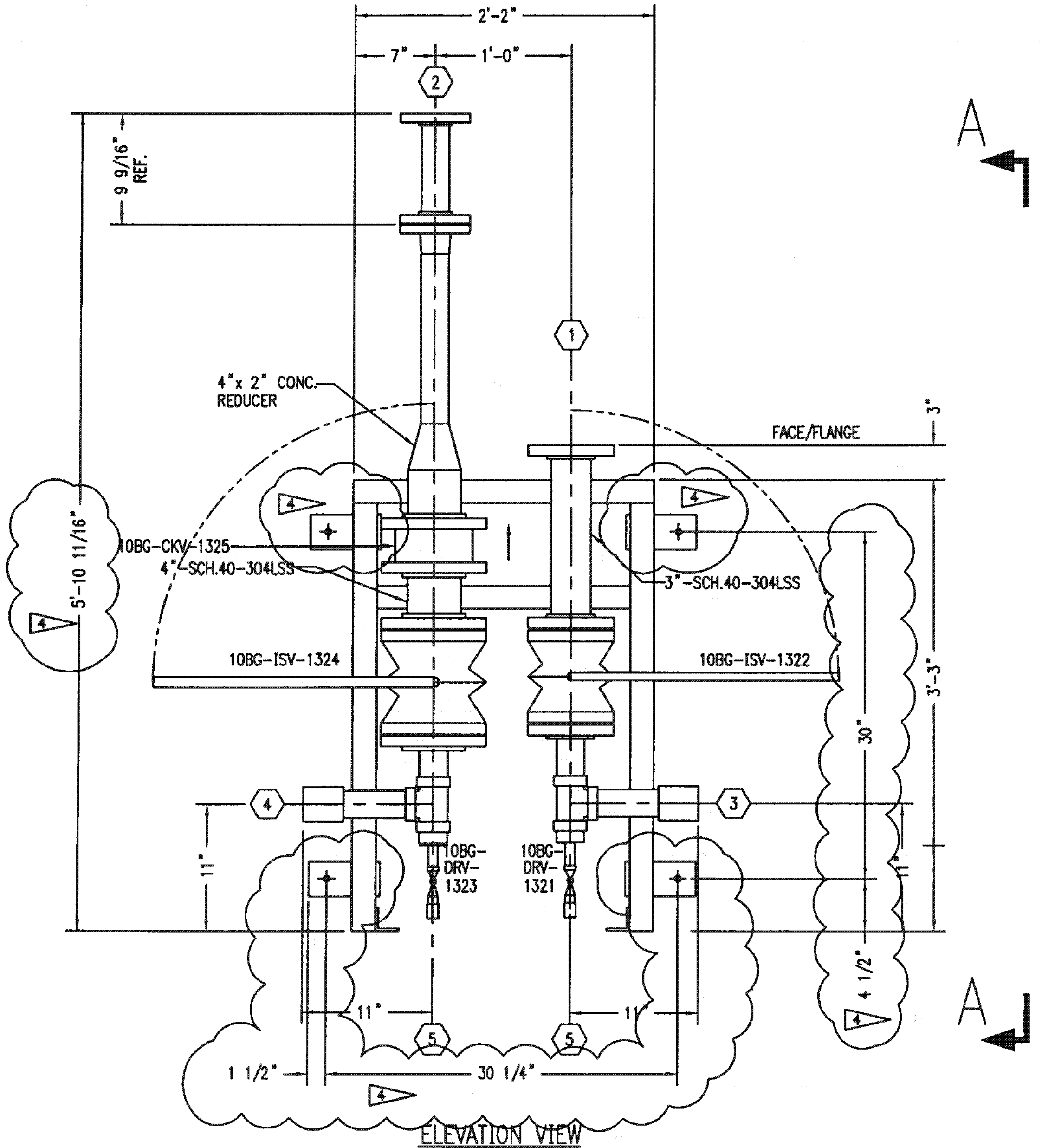
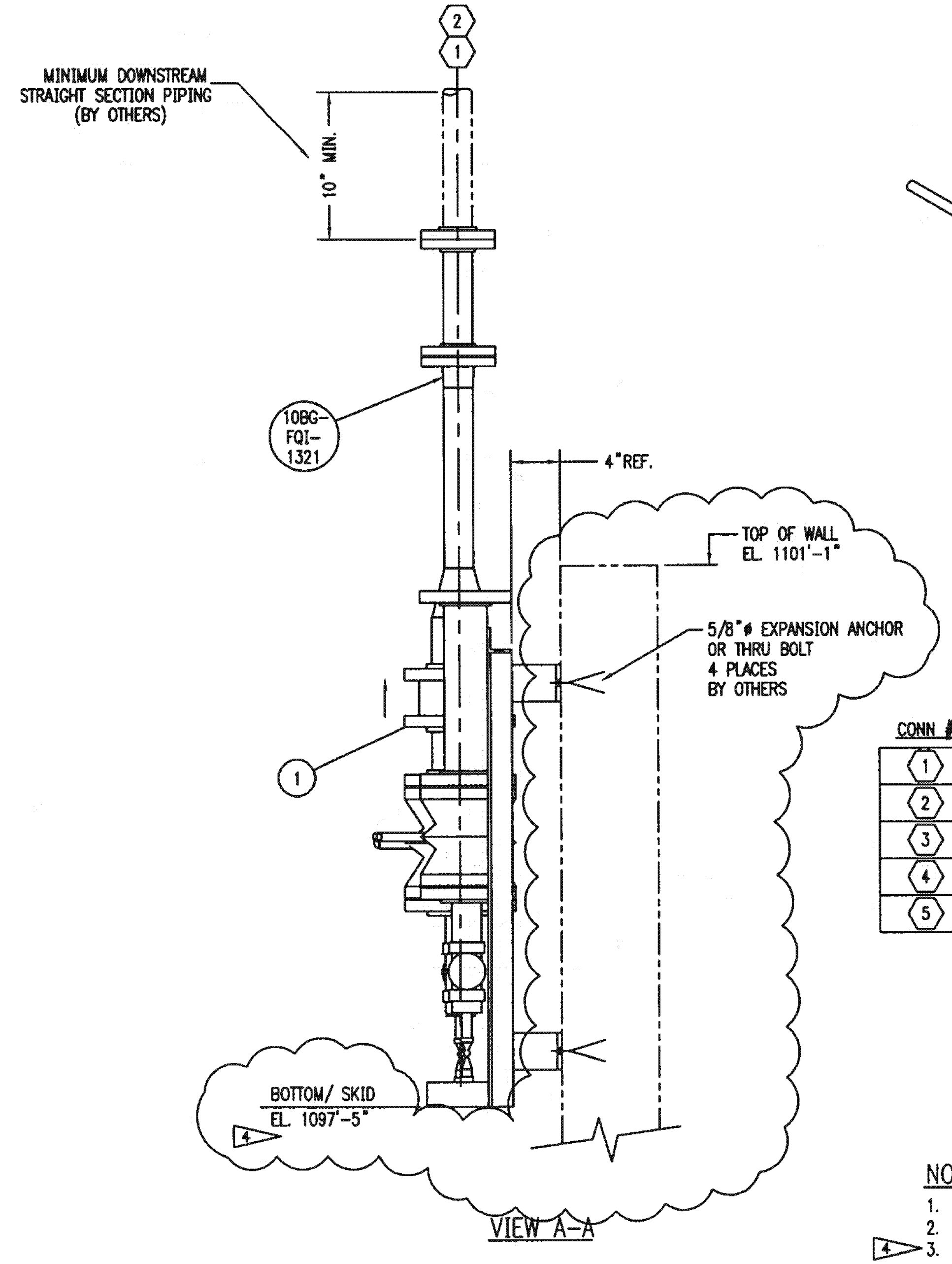


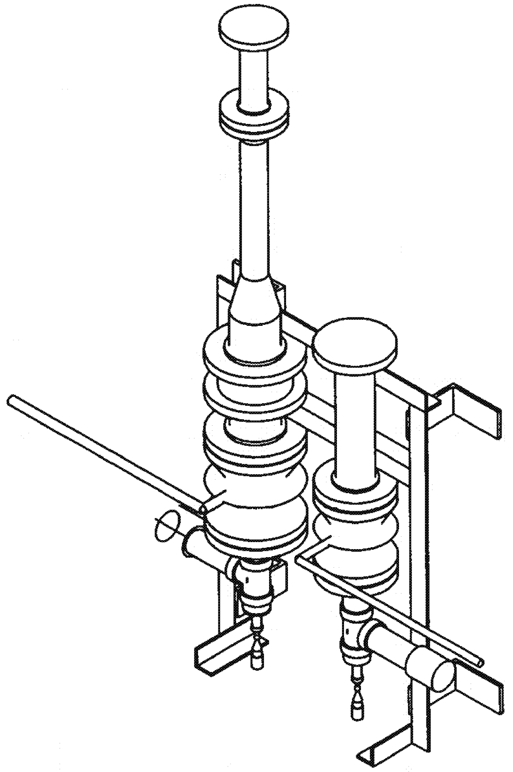
PLAN VIEW



ELEVATION VIEW



VIEW A-A



NOZZLE IDENTIFICATION

CONN #	DESCRIPTION	CONN SIZE
1	RETURN FROM TANK	3" 150# R.F. FLANGE
2	AMMONIA TO TANK	2" 150# R.F. FLANGE
3	RETURN TO TRUCK	2" CAMLOCK
4	AMMONIA SUPPLY FROM TRUCK	2" CAMLOCK
5	PURGE CONNECTION (2 PLACES)	1/2" NPT (CAPPED)

NOTES:

1. ALL FLANGE BOLT HOLES TO STRADDLE CENTERLINES.
2. SURFACE PREP AND PAINT PER CHEMITHON SPEC MF0100, SECTION 2.2.1.
3. 4 TOTAL ESTIMATED WEIGHT = 255 LBS.
4. SEE DRAWING NO. PID-1300002 FOR P&ID.

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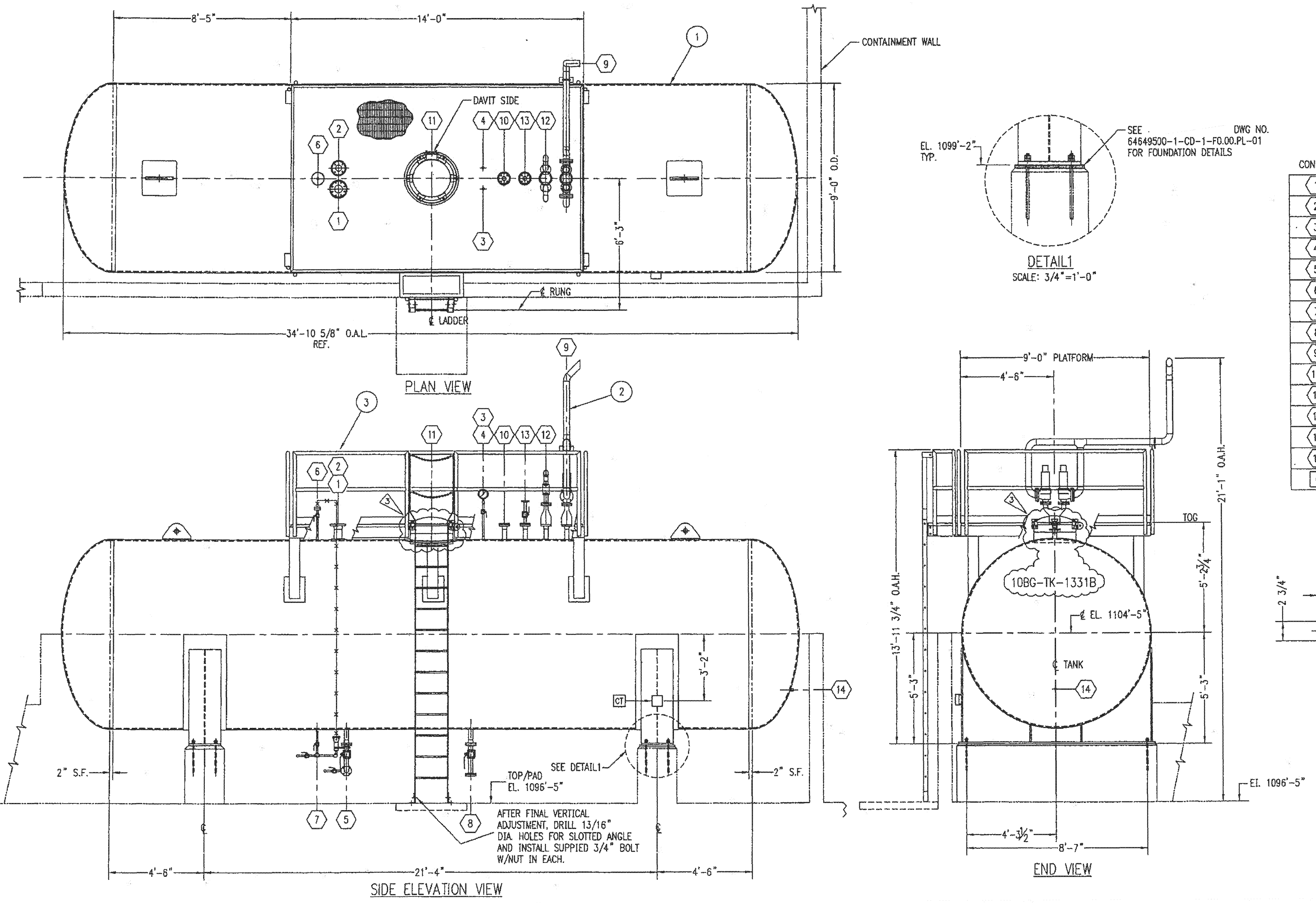
SAPPI FINE PAPER NORTH AMERICA
CLOQUET, MN
NO. 9 POWER BOILER SNCR
AMMONIA TRUCK UNLOADING ASSEMBLY

AutoCAD DRAWING UNITS: NTS
JOB No. 2011-0025
DWG No. 2011-0025-D-RA-5
REV A

File: RA5.dwg Date/Time: September 27, 2011 11:22 a.m. Scale: 1=1, Printed by: MikeW



PLAN VIEW

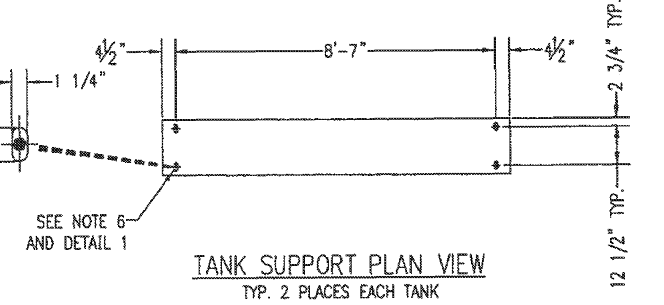
DETAIL1
SCALE: 3/4"=1'-0"

SIDE ELEVATION VIEW

END VIEW

NOZZLE IDENTIFICATION

CONN #	DESCRIPTION	CONN SIZE	NOZZLE PROJECTION
1	FILL CONNECTION	4" 150# WN FLG.	9"
2	VAPOR RETURN	3" 150# WN FLG.	8 3/4"
3	PRESSURE INDICATOR	1/2" 3000# NPT.	—
4	PRESSURE SWITCH	1/2" 3000# NPT.	—
5	DISCHARGE CONNECTION	2" 150# WN FLG.	8 1/2"
6	Dp CONNECTION	1/2" 3000# NPT.	—
7	Dp CONNECTION	1/2" 3000# NPT.	—
8	DRAIN	2" 150# WN FLG.	8 1/2"
9	PRESSURE RELIEF CONNECTION	2" 150# WN FLG.	8 1/2"
10	SPARE	2" 150# WN FLG.	8 1/2"
11	MANWAY	24" DIAMETER	—
12	VACUUM RELIEF CONNECTION	2" 150# WN FLG.	8 1/2"
13	RECYCLE INLET CONNECTION	2" 150# WN FLG.	8 1/2"
14	TEMPERATURE CONNECTION	3/4" 3000# NPT	—
C	CODE TAG MOUNTING BRACKET	CHEMITHON STD.	



TANK SUPPORT PLAN VIEW
TYP. 2 PLACES EACH TANK

NOTES:

1. TOTAL ESTIMATED WEIGHT = 22,050 LBS.(EMPTY) 152,400 LBS.(FLOODED)
2. ALL ASSEMBLIES TO BE FABRICATED AND SUPPLIED BY CHEMITHON.
3. VESSEL CAPACITY IS 15,000 GAL. IN VOLUME.
4. ALL FOUNDATION LABOR AND MATERIALS TO BE FURNISHED BY CUSTOMER.
5. SEE DWG. 0V1331 FOR FABRICATION CODE NOTES.
6. ANCHOR BOLTS SHOULD BE LOCATED ON THE CENTER OF THE 2 3/4" LONG SLOTS. DOUBLE NUT BOTH NORTH AND SOUTH ANCHOR BOLTS. TIGHTEN DOUBLE NUTS TIGHT ON SOUTH END OF AMMONIA TANKS SUPPORT PAD. LEAVE DOUBLE NUTS LOOSE ON NORTH END OF AMMONIA TANKS SUPPORT PAD AND USE THESE DOUBLE NUTS TO LOCK IN POSITION.

3 7. TANK 10BG-TK-1331B ON EAST SIDE.

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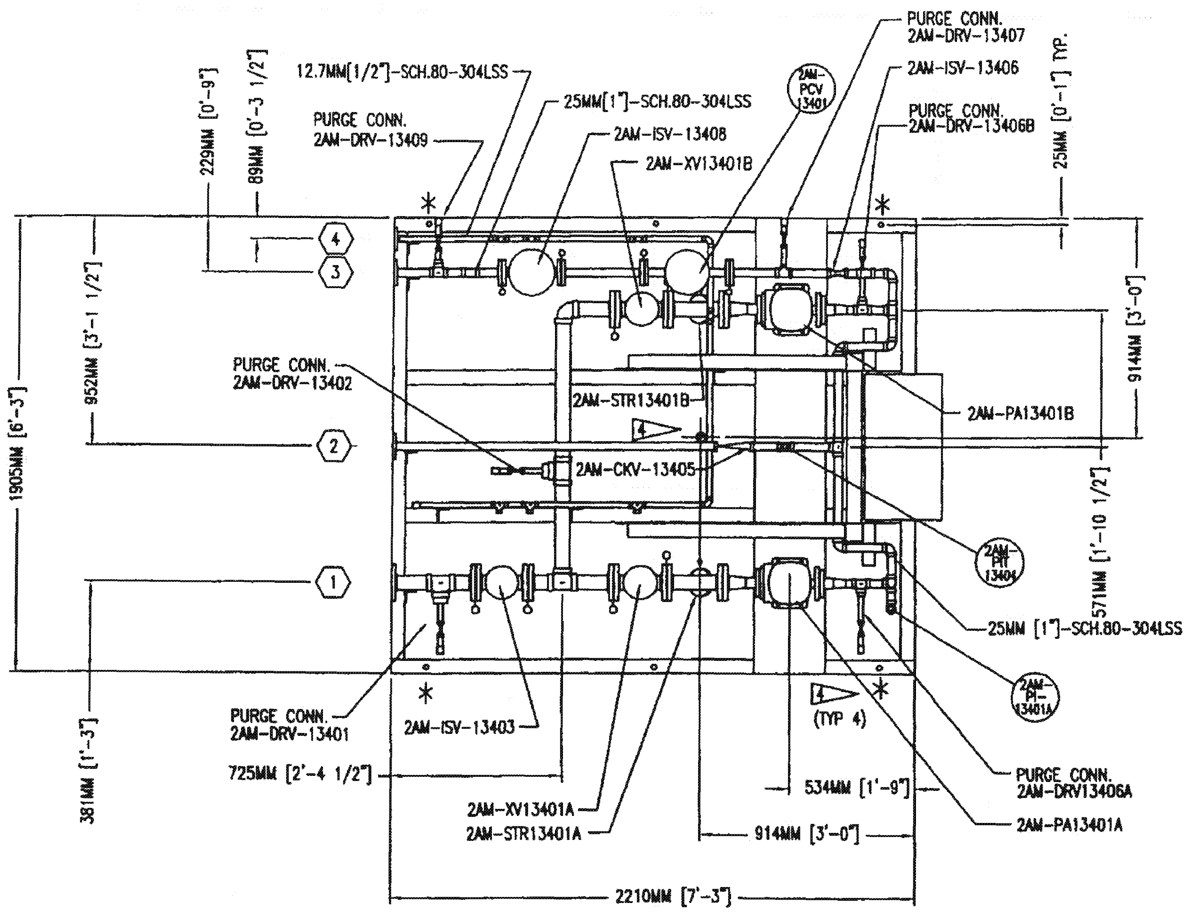
NO. 9 POWER BOILER SNCR
AQUEOUS AMMONIA STORAGE TANK
GENERAL ASSEMBLY

AutoCAD DRAWING UNITS: NTS
JOB No. 2011-0025
DWG No. 2011-0025-D- RA-6
REV A

File: RA6.dwg Date/Time: September 27, 2011 11:22 a.m. Scale: 1=1, Printed by: MikeW



PLAN VIEW
SEE NOTE 6

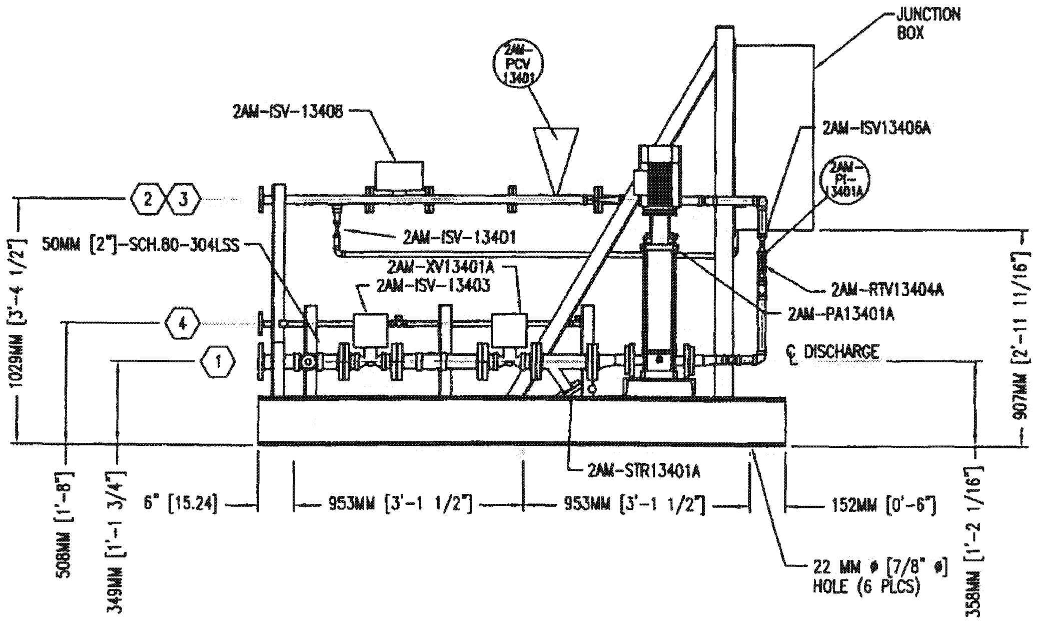
NOZZLE IDENTIFICATION

CONN #	DESCRIPTION	CONN SIZE
1	AMMONIA INLET	50.8MM [2"] 150# RF FLANGE
2	AMMONIA TO METERING MODULE	25.4MM [1"] 150# RF FLANGE
3	AMMONIA RETURN TO TANK	25.4MM [1"] 150# RF FLANGE
4	INSTRUMENT AIR INLET	12.7MM [1/2"] 150# RF FLANGE

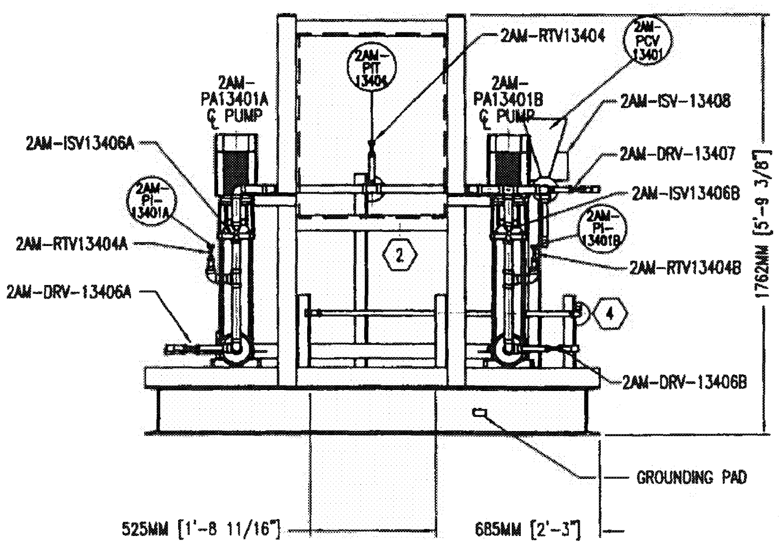
NOTES:

1. ALL FLANGE BOLT HOLES TO STRADDLE CENTERLINES.
2. REFERENCE DRAWING NO. 0-PID13000-03.
3. SHIM U-BOLTS, PIPING AND PUMPS FOR PROPER FIT & ALIGNMENT.
4. TOTAL ESTIMATED WEIGHT = 368.32 Kg [812 LBS]

✱ = LIFT POINT
⌖ = CENTER OF GRAVITY



ELEVATION VIEW



END VIEW

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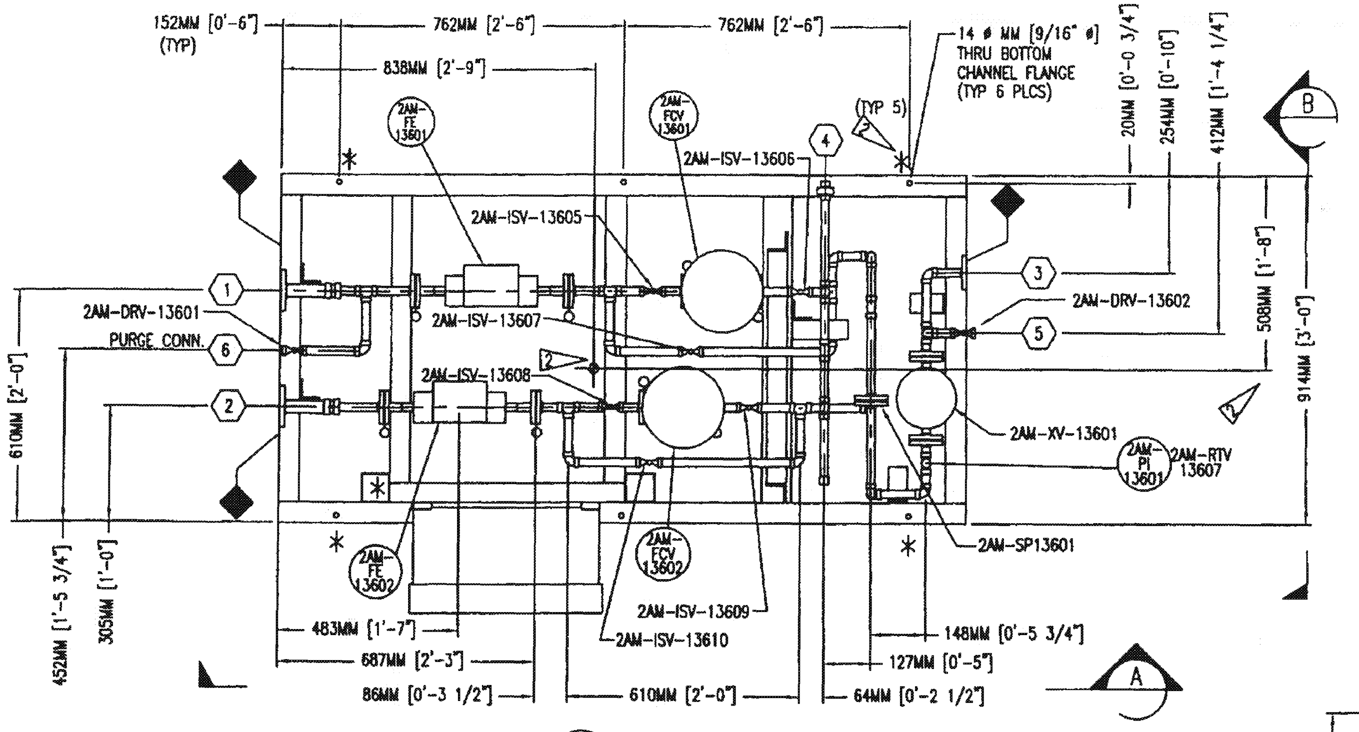
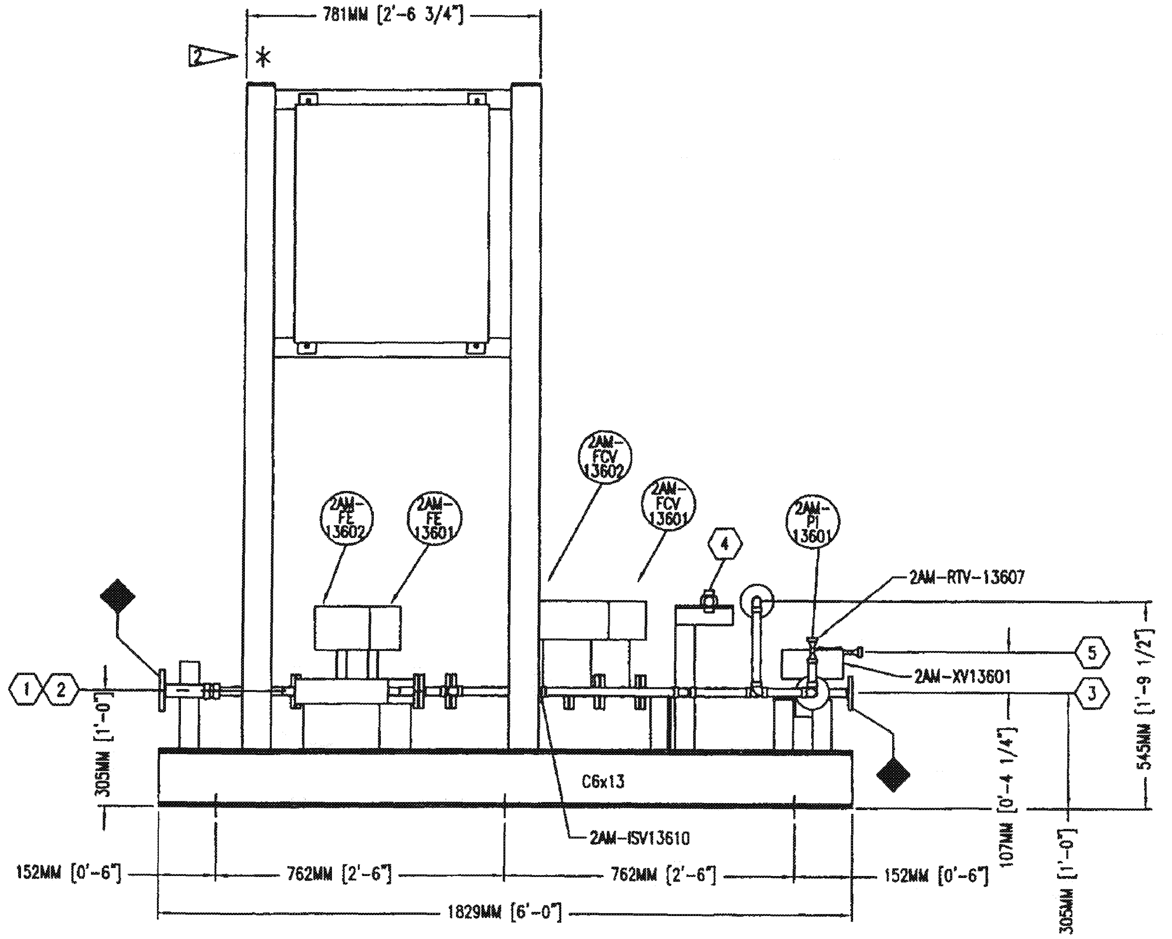
NO. 9 POWER BOILER SNCR
AQUEOUS AMMONIA CIRCULATING
PUMP SKID GENERAL ASSEMBLY

AutoCAD DRAWING UNITS: NTS
JOB No. 2011-0025
DWG No. 2011-0025-D-RA-7
REV A

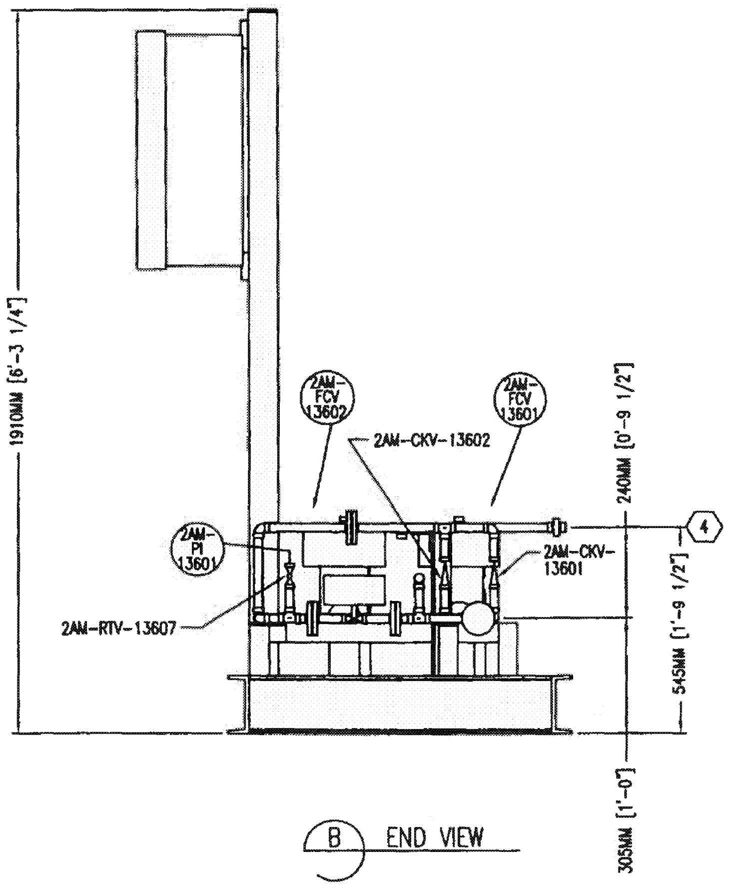
File: RA7.dwg Date/Time: September 27, 2011 11:21 a.m. Scale: 1=1, Printed by: MikeW



PLAN VIEW



A ELEVATION VIEW



B END VIEW

NOZZLE IDENTIFICATION

CONN #	DESCRIPTION	CONN SIZE
1	AMMONIA INLET FROM AMMONIA PUMPS	25MM [1"] 150# R.F. FLANGE
2	DILUTION WATER FROM DILUTION WATER PUMPS	25MM [1"] 150# R.F. FLANGE
3	TO INJECTION SYSTEM	13MM [1/2"] 150# R.F. FLANGE
4	INSTRUMENT AIR INLET	13MM [1/2"] SW UNION
5	PURGE CONNECTION	13MM [1/2"] SW
6	PURGE CONNECTION	13MM [1/2"] SW

NOTES:

1. ALL FLANGE BOLT HOLES TO STRADDLE CENTERLINES.
2. REFERENCE DRAWING 0-PID13000-04.
3. TOTAL ESTIMATED WEIGHT = 1100 LBS. [498.95Kg]

2 ✱ = LIFT POINT

⊕ = CENTER OF GRAVITY

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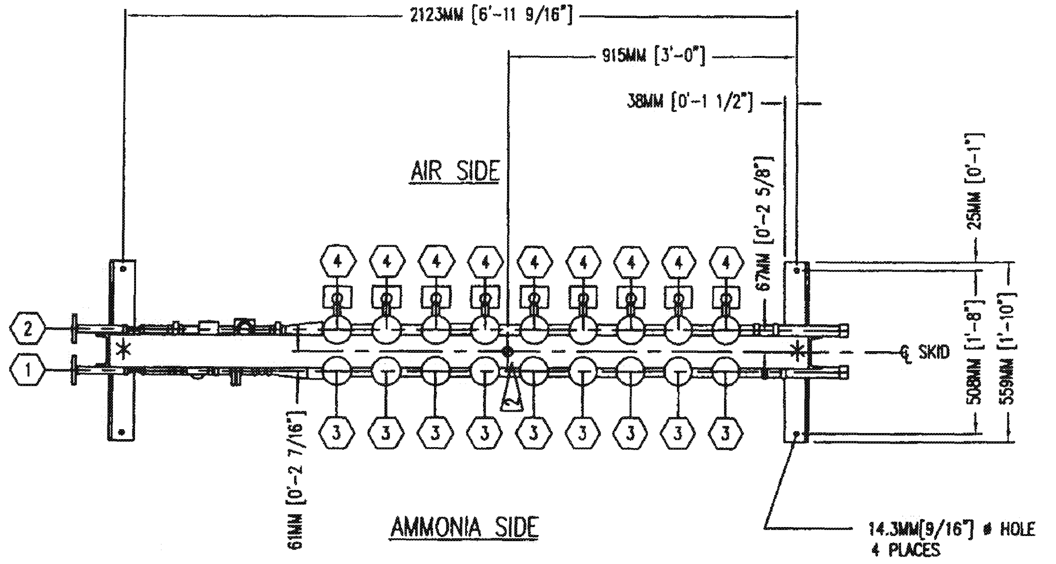
NO. 9 POWER BOILER SNCR
AQ NH3-H20 METERING SKID
GENERAL ASSEMBLY

AutoCAD DRAWING UNITS: NTS
JOB No. 2011-0025
DWG No. 2011-0025-D- RA-8
REV A

File: RA8.dwg Date/Time: September 27, 2011 11:21 a.m. Scale: 1=1, Printed by: MikeW



PLAN
SEE NOTE 5

NOZZLE IDENTIFICATION

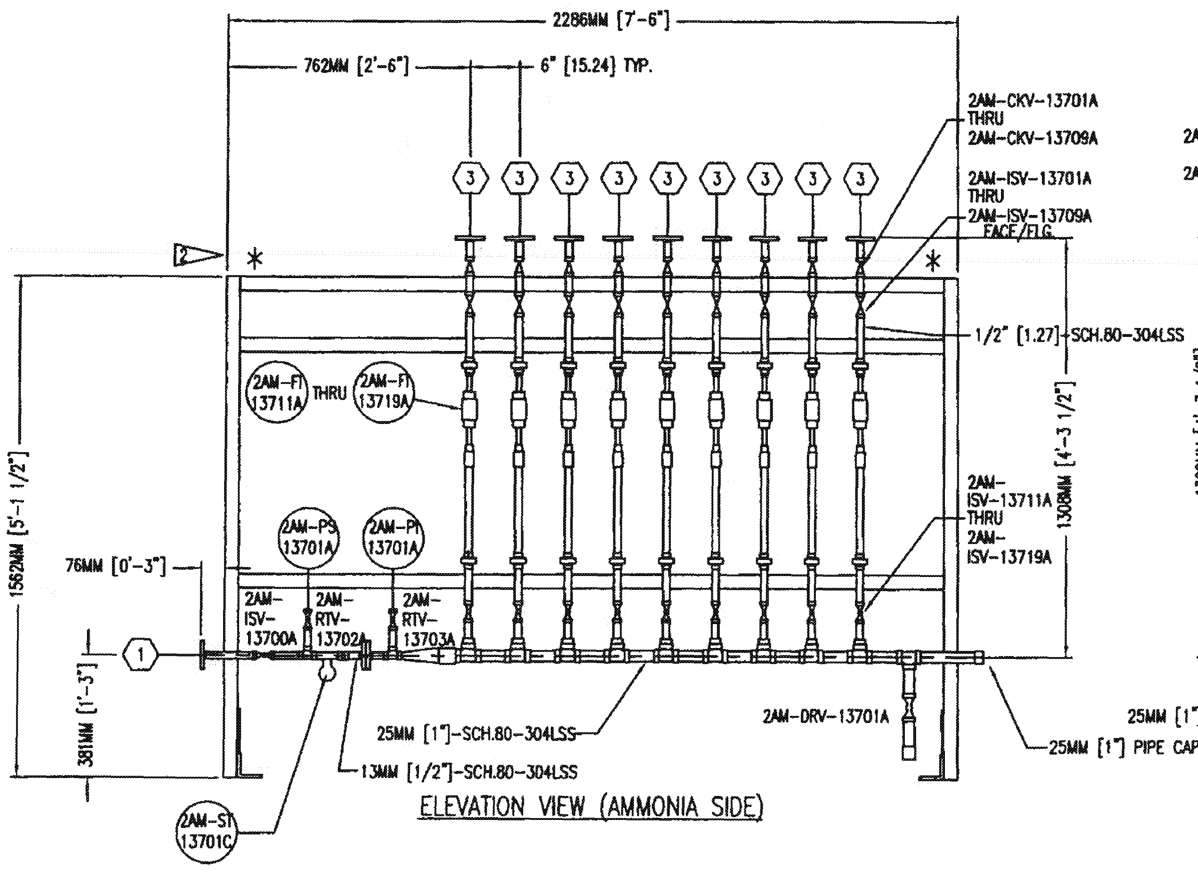
CONN #	DESCRIPTION	CONN SIZE
1	AMMONIA INLET TO DISTRIBUTION RACK	1/2" [1.27] 150# FLANGE
2	ATOMIZING AIR	1/2" [1.27] 150# FLANGE
3	AMMONIA DISTRIBUTION RACK OUTLET	1/2" [1.27] 150# FLANGE
4	ATOMIZING AIR DISTRIBUTION RACK OUTLET	1/2" [1.27] 150# FLANGE

NOTES:

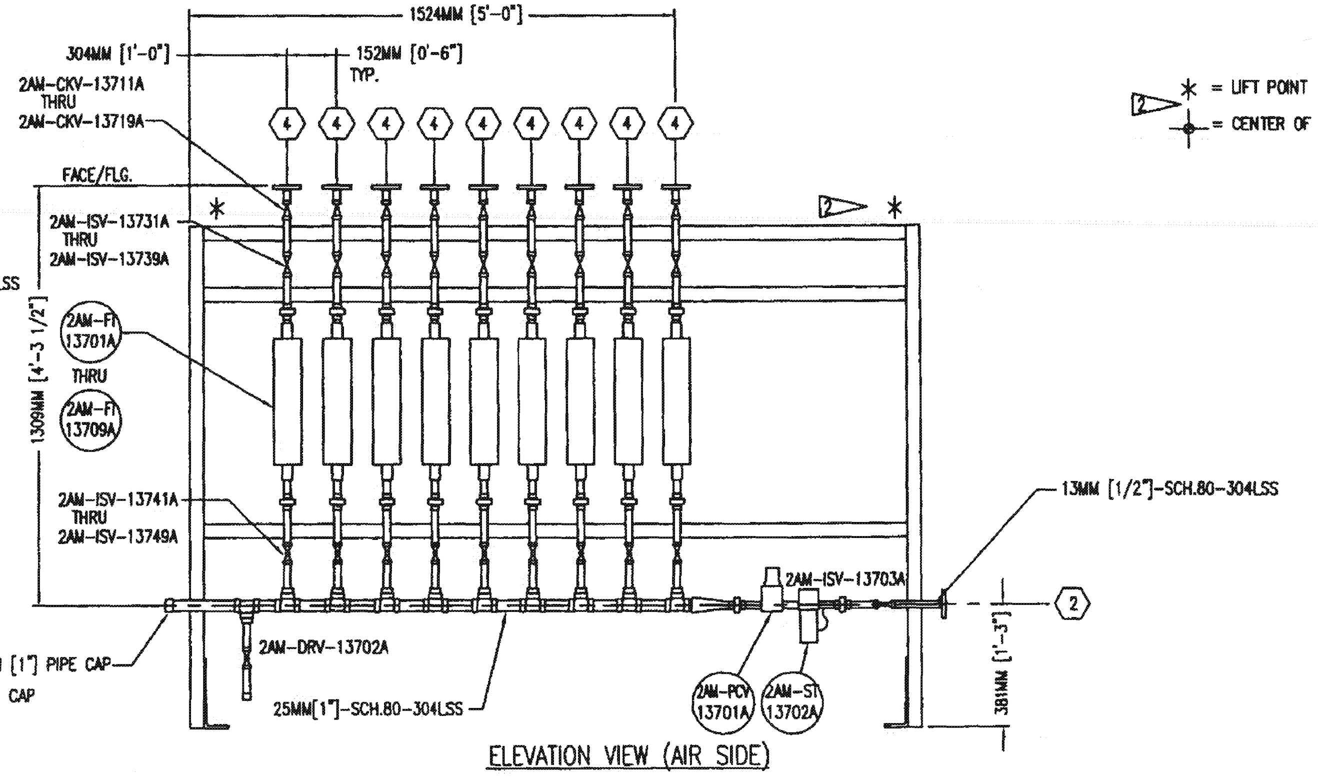
1. ALL FLANGE BOLT HOLES TO STRADDLE CENTERLINES.
2. TOTAL ESTIMATED WEIGHT: 226.80 Kg [500 LBS]
3. SEE DRAWING NO. 0-PID13000-07.

2▷ * = LIFT POINT

⌖ = CENTER OF GRAVITY



ELEVATION VIEW (AMMONIA SIDE)



ELEVATION VIEW (AIR SIDE)

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CLOQUET, MN

NO. 9 POWER BOILER SNCR
AQUEOUS AMMONIA INJECTION
SKID ASSEMBLY – UNIT 2A

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JOB No. 2011–0025
DWG No. 2011–0025–D–RA-9
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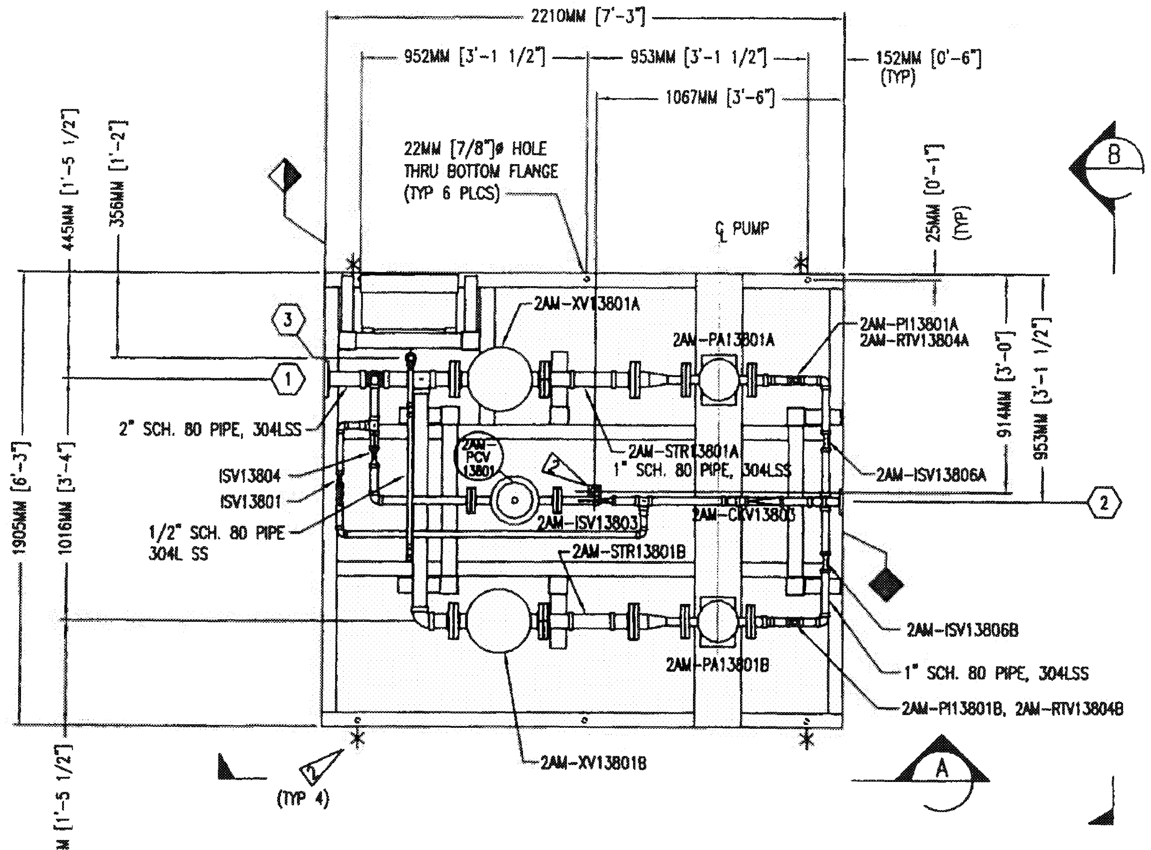
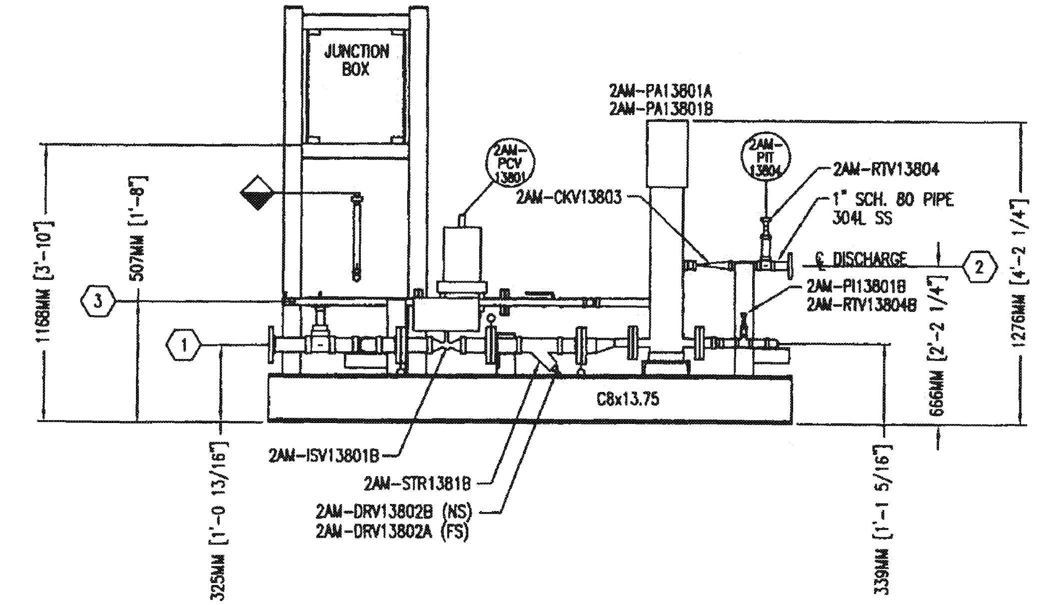
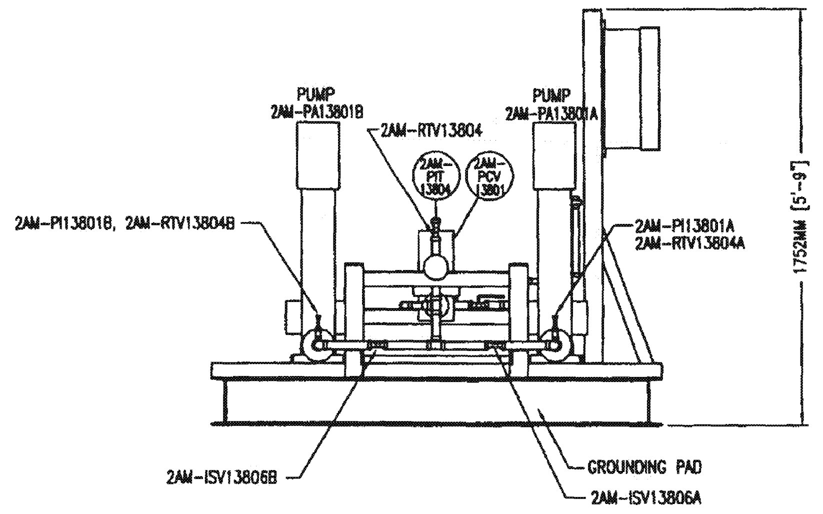


PLAN VIEW



A FRONT ELEVATION



B END ELEVATION

NOZZLE IDENTIFICATION

CONN #	DESCRIPTION	CONN SIZE
1	PLANT SERVICE WATER INLET	50MM[2"] 150# R.F. FLANGE
2	DILUTION WATER TO AMMONIA/WATER METERING MODULES	25MM[1"54] 300# R.F. FLANGE
3	INSTRUMENT AIR INLET	13MM [1/2"] SW UNION

NOTES:

1. ALL FLANGE BOLT HOLES TO STRADDLE CENTERLINES.
2. SEE DRAWING NO. PID-01300005 FOR P & ID.
3. SHIM U-BOLTS, PIPING AND PUMPS FOR PROPER FIT & ALIGNMENT.
4. TOTAL ESTIMATED WEIGHT = 408.23 Kg [900 LBS]

✱ = LIFT POINT

2 ⌖ = CENTER OF GRAVITY

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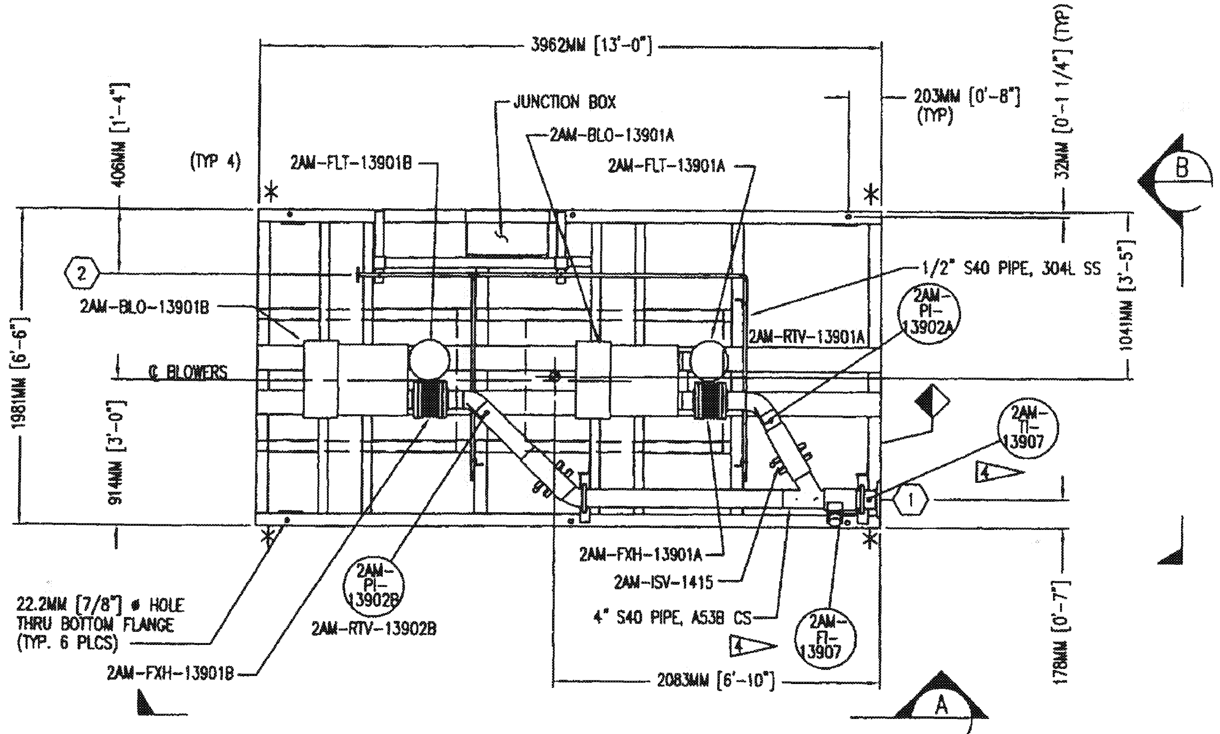
CLOQUET, MN

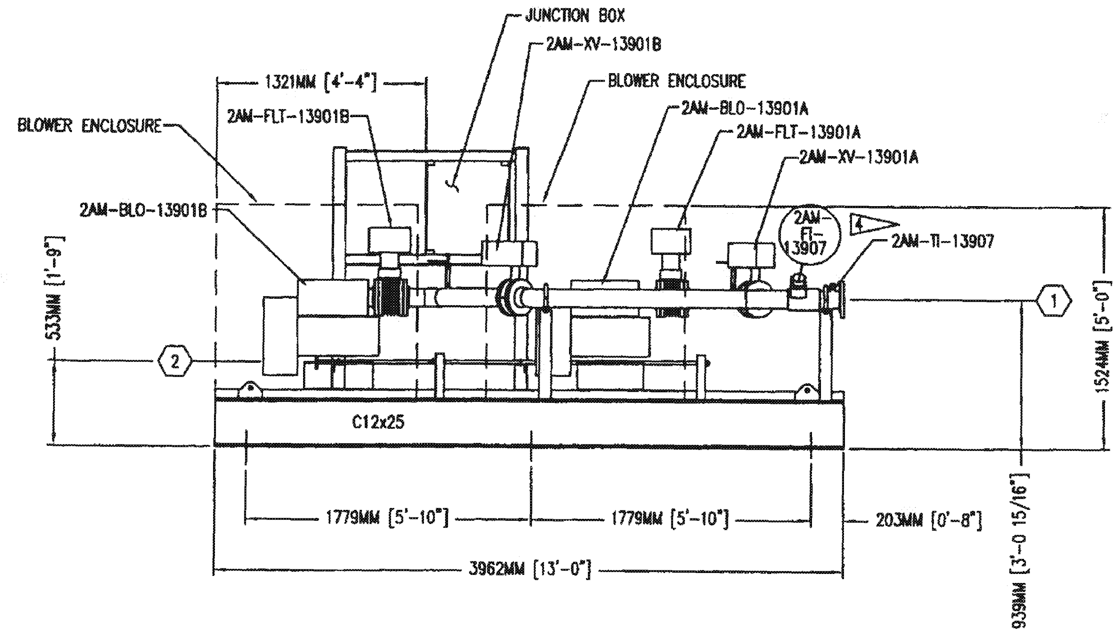
NO. 9 POWER BOILER SNCR
DILUTION WATER PUMP SKID
GENERAL ASSEMBLY

AutoCAD DRAWING UNITS: NTS
JOB No. 2011-0025
DWG No. 2011-0025-D-RA-10
REV A

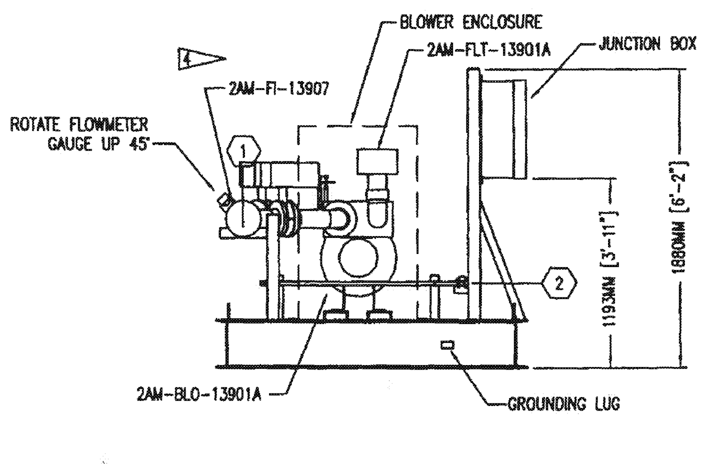
File: RA10.dwg Date/Time: September 27, 2011 11:20 a.m. Scale: 1=1, Printed by: MikeW



PLAN VIEW



A ELEVATION VIEW



B END VIEW

NOZZLE IDENTIFICATION

CONN #	DESCRIPTION	CONN SIZE
1	COOLING AIR TO INJECTORS	101.6MM [4"] 150# R.F. FLANGE
2	INSTRUMENT AIR	12.7MM [1/2"] 150# RF FLANGE

NOTES:

1. ALL WELDING TO BE PER CHEMITHON WELD PROCEDURES.
2. TOTAL ESTIMATED WEIGHT = 1678 Kg [3700 LBS]
3. SEE DWG., NO. PID-1300006 FOR P&ID.

✱ = LIFT POINT

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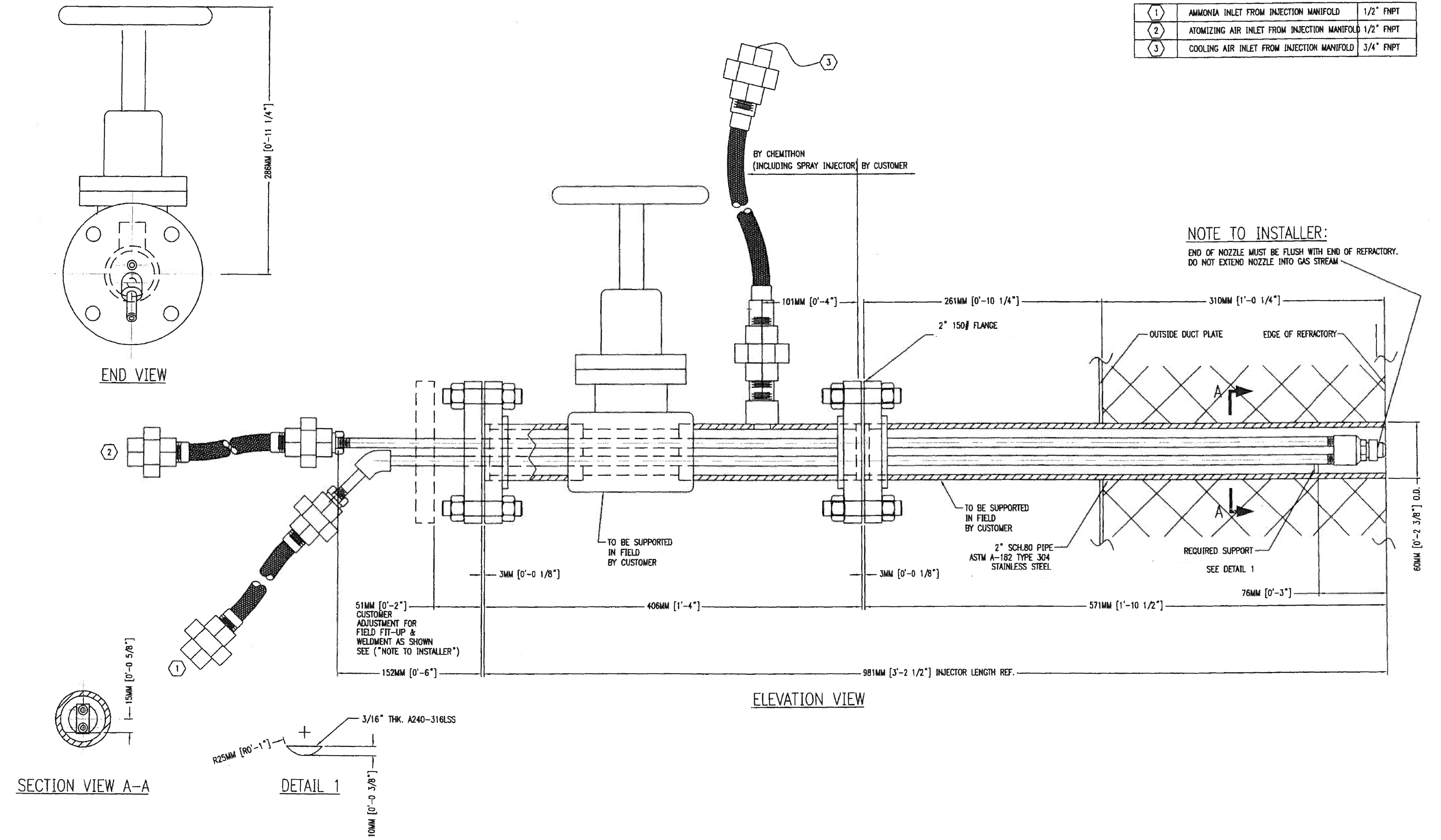
NO. 9 POWER BOILER SNCR
COOLING AIR SUPPLY SKID
GENERAL ASSEMBLY

AutoCAD DRAWING UNITS: NTS
JOB No. 2011-0025
DWG No. 2011-0025-D-RA-11
REV A

NOZZLE IDENTIFICATION

CONN #	DESCRIPTION	CONN SIZE
1	AMMONIA INLET FROM INJECTION MANIFOLD	1/2" FNPT
2	ATOMIZING AIR INLET FROM INJECTION MANIFOLD	1/2" FNPT
3	COOLING AIR INLET FROM INJECTION MANIFOLD	3/4" FNPT



NOTE TO INSTALLER:

END OF NOZZLE MUST BE FLUSH WITH END OF REFRACTORY.
DO NOT EXTEND NOZZLE INTO GAS STREAM

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CLOQUET, MN

NO. 9 POWER BOILER SNCR
AQUEOUS AMMONIA INJECTION
ASSEMBLY

AutoCAD DRAWING UNITS: NTS
JOB No. 2011-0025
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REV A

resourceful. naturally.
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BARR

Technical Memorandum

To: Sappi Cloquet LLC (Sappi)
From: Barr Engineering Co. (Barr)
Subject: Regional Haze Four-Factor Analysis (FFA): Evaluation Updates
Date: March 29, 2022

In January 2020 the Minnesota Pollution Control Agency (MPCA) requested that Sappi conduct a Regional Haze Four-Factor Analysis (FFA) for certain emission units and pollutants at their facility in Cloquet, Minnesota. The FFA is a regulatory requirement for the mandatory Regional Haze State Implementation Plan (SIP) update. The FFA reports are intended to inform decisions regarding the emission reductions that are necessary to make reasonable progress on visibility improvements in Class I areas. Barr provided technical support to Sappi in preparation of the FFA, and Sappi submitted the initial FFA report on July 17, 2020. Sappi provided additional information on July 28, 2021, in response to requests from MPCA.

On January 10, 2022, the MPCA contacted Sappi to schedule a meeting to discuss their review of the Sappi's FFA and to provide an update on the Regional Haze SIP development in general. Meetings with MPCA were conducted on January 24 and February 14, 2022. During these meetings the MPCA informed Sappi that they believe the installation of a selective non-catalytic reduction (SNCR) on Power Boiler #9 (EQUI 4) is cost effective and necessary to make reasonable progress as part of the Regional Haze SIP. A follow-up meeting is scheduled for March 31, 2022.

This memorandum is a supplement to the 2020 FFA and has been completed in support of Sappi's response to MPCA regarding Power Boiler #9 (EQUI 4).

Section 1 presents the updated SNCR control cost evaluation to reflect 2022 costs, superseding the prior cost study included in the initial FFA. The new costs reflect site- and source-specific engineering and construction estimates to install and operate SNCR on Boiler #9 (EQUI 4).

Section 2 presents Barr's evaluation of the progress that has been made towards natural visibility at Voyageurs National Park (Voyageurs), Boundary Waters Canoe Area (Boundary Waters) and Isle Royale National Park (Isle Royale). This information is related to the requirement for the SIP update to include an evaluation of the uniform rate of progress (URP)[1] and to develop a long-term strategy which includes emission reductions which are necessary to make reasonable progress[2].

Section 3 presents an analysis of how the proposed NO_X emission reduction from Power Boiler #9 (EQUI 4) could impact visibility. This information is related to an additional "fifth factor" analysis for visibility benefit that MPCA can consider before determining if emission reductions or control technologies are necessary to make reasonable progress.

Section 4 presents the conclusions based on the information presented in this document.

1 Control Cost Analysis

The 2020 FFA included a SNCR control cost evaluation for Power Boiler #9 (EQUI 4) which was based on a 2012 study by Jansen Combustion and Boiler Technologies, Inc. (Jansen). The in the 2012 Jansen report was adjusted for inflation to 2020 costs. The 2012 Jansen report was submitted to MPCA in 2021 as supplemental information.

To represent present day costs more accurately, Sappi updated capital costs with new cost estimates from Jansen, The Jamar Company (Jamar), and Hunt Electric Corporation (Hunt). Sappi's engineering staff reviewed the new cost estimates and confirmed that the bids were reasonable based on previous project experience. Barr updated the control cost evaluation to reflect this updated information. The updated analysis is presented in Attachment A.

The cost effectiveness analysis compares the annualized cost of the technology 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. The updated SNCR cost effectiveness is $9,528 per ton of NO_x removed. The original SNCR cost evaluation, the control costs that MPCA presented to Sappi in January 2022, and the updated control costs are summarized in Table 1-1.

---

[1] 40 CFR 51.308(f)(1)

[2] 40 CFR 51.308(f)(2)

Table 1-1: Power Boiler #9 (EQUI 4) SNCR Cost Effectiveness Comparison

Additional Emissions Control Measure	Total Capital Investment ($)	Total Annualized Costs ($/year)	Annual Emissions Reduction (tpy)	Pollution Control Cost Effectiveness ($/ton)
SNCR (2020 estimate)	$5,021,391	$623,834	96.8 tpy	$7,191/ton
SNCR (2022 MPCA[3])	$5,408,165	$622,190	87 tpy	$7,632/ton
SNCR (2022 Update)	$6,068,270	$826,547	87 tpy[4]	$9,528/ton

2 Progress Towards Natural Visibility

The information below provides an overview of the baseline, current, and natural visibility conditions, including the progress to date and the URP as required to be included in the SIP update.[5] The SIP "must consider the uniform rate of improvement in visibility and the emission-reduction measures needed to achieve it for the period covered by the implementation plan."[6]

2.1 IMPROVE Data Analysis

MPCA tracks progress towards the natural visibility conditions using data from the IMPROVE visibility monitors at Boundary Waters (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1).[7] The visibility metric is based on the 20% most anthropogenically impaired days and the 20% clearest days, with visibility being measured in deciviews (dv). USEPA issued guidance for tracking visibility progress, including the methods for selecting the "most impaired days," on December 20, 2018.[8] Originally, the RHR considered the "haziest days" but USEPA recognized that naturally occurring events (e.g., wildfires and dust storms) could be contributing to visibility and that the "visibility improvements resulting from decreases in anthropogenic emissions can be hidden in this uncontrollable natural variability."[9] In addition, the RHR allows a state to

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[3] Bouchareb, Hassan (MPCA) presentation "Regional Haze Update – 2nd Implementation Period" January 2022

[4] Ibid.

[5] 40 CFR 51.308(f)

[6] 40 CFR 51.308(d)(1)

[7] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

[8] https://www.epa.gov/visibility/technical-guidance-tracking-visibility-progress-second-implementation-period-regional

[9] USEPA, Federal Register, 05/04/2016, Page 26948

account for international emissions "to avoid any perception that a state should be aiming to compensate for impacts from international anthropogenic sources."[10]

Barr evaluated updated visibility monitoring data for Boundary Waters, Voyageurs, and Isle Royale to compare the current conditions to the natural visibility goal, and URP. Since the initial request for information, the targeted "natural" conditions have been revised[11], and are incorporated in the associated charts and calculations of URP targets.

The updated datasets shown in Figure 2-1 through Figure 2-3 reiterate previous analyses of current visibility conditions at the three Class I areas being evaluated by MPCA. Since 2009, the regional haze impairment at all three Class I areas has been declining (i.e., visibility has been improving). Additionally, regional haze impairment fell below the expected 2028 URP in 2016 for Boundary Waters and Isle Royale, and 2018 for Voyageurs. The existing visibility data demonstrates sustained progress towards visibility goals and the 5-year average visibility impairment on the most impaired days is already below the 2028 URP.

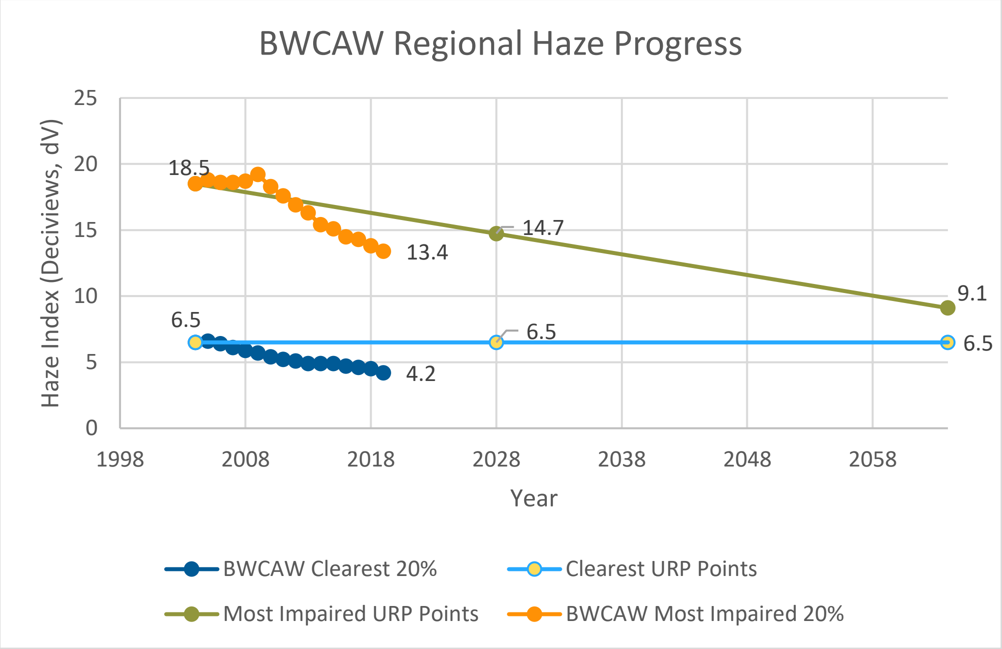

Figure 2-1. Visibility Trend versus URP – Boundary Waters Canoe Area Wilderness (BOWA1)

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[10] USEPA, Federal Register, 01/10/2017, Page 3104

[11] http://vista.cira.colostate.edu/DataWarehouse/IMPROVE/Data/SummaryData/Endpoint/glideslope_and_2064_endpt_4_20_2.csv

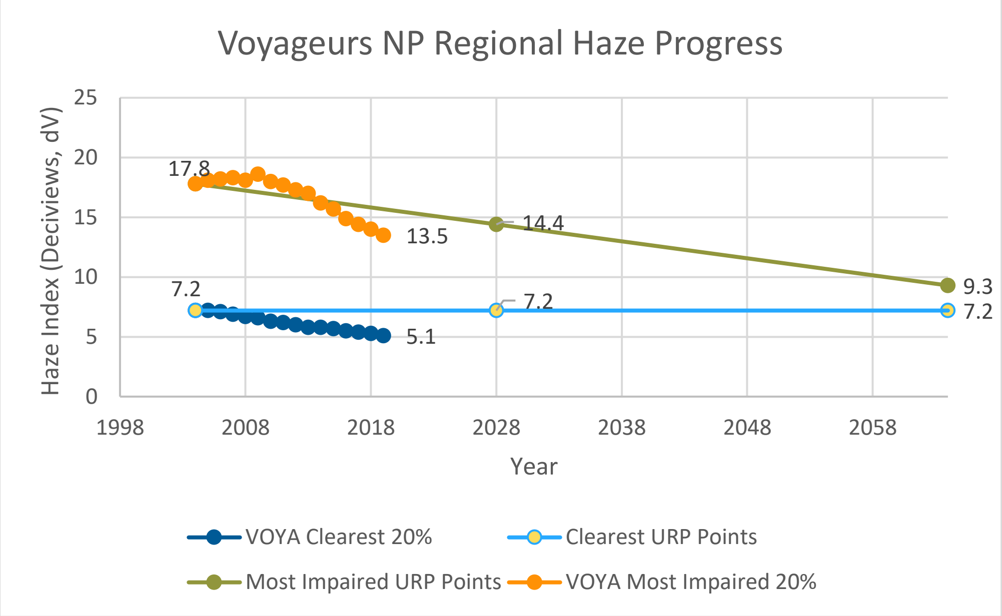

Figure 2-2. Visibility Trend versus URP – Voyageurs National Park (VOYA2)

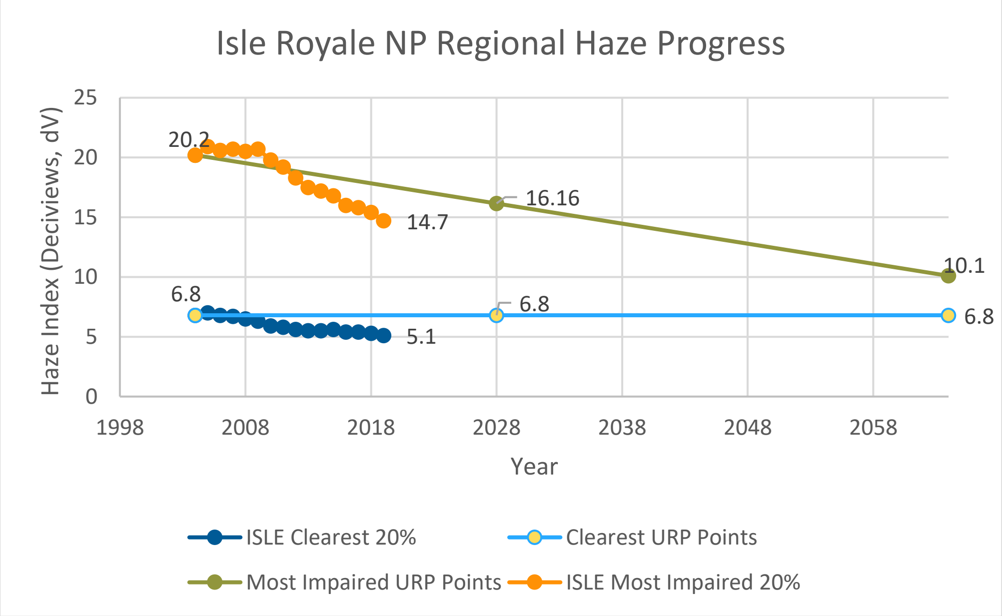

Figure 2-3. Visibility Trend versus URP – Isle Royale National Park (ISLE1)

2.2 Additional Expected Reductions

In addition to the above-noted trends falling below the URP goal, many facilities have implemented emission reduction actions that are not yet fully represented in the 5-year averages which are shown in Figure 2-1 through Figure 2-3, and others emission reductions are planned in the future including:

- Minnesota Power Boswell Energy Center in Cohasset:
    - Retired two coal-fired boilers at the at the end of 2018 which is reflected in the facility annual NO_X emissions which decreased from average of 4,198 tons/year in 2016-2017 to 2,196 tons/year in 2019-2020[12]
    - Retiring Unit 3 by year-end 2029[13]
    - Ceasing coal operations at Unit 4 in 2035[14]
- The Federal Implementation Plan (FIP) Establishing BART for Taconite Plants (40 CFR 52.1235) requires NO_X emission controls at several Minnesota sources and the full implementation of these emission reductions is just being realized; for example, Hibbing Taconite has three lines which required installation of low-NO_X burners in 2018, 2020 and 2021[15] and the annual NO_X emissions from the facility[16] has decreased in each of the last five years:
    - 2016 = 4,313 tons
    - 2017 = 3,981 tons
    - 2018 = 3,227 tons
    - 2019 = 2,827 tons
    - 2020 = 1,594 tons
- Otter Tail Power retired Hoot Lake Plant in 2021 which had annual NO_X emissions of approximately 400 tons per year[17]
- Xcel Energy is committed to reducing carbon emissions 80% by 2030 and provide 100% carbon-free energy by 2050[18] which will result in decreased emissions of NO_X and SO_2, including the retirement of the following coal-fired resources in Minnesota representing over 6,400 tons per year of NOx:
    - Sherco Unit 2 in 2023

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[12] https://www.pca.state.mn.us/air/permitted-facility-air-emissions-data

[13] Minnesota Power 2021 Integrated Resource Plan

[14] Ibid.

[15] 40 CFR 52.1235(b)(1)(ii)

[16] https://www.pca.state.mn.us/air/permitted-facility-air-emissions-data

[17] Ibid.

[18] Xcel Energy 2020 Upper Midwest Integrated Resource Plan

  - Sherco Unit 1 in 2026
  - Allen King in 2028
  - Sherco in 2030

While some of these reductions were implemented in 2018 (two units at Boswell, as well as some taconite controls), the data points reflect a 5-year average thus the effects on the 2018 and 2019 data points do not yet include the full impact of these changes. Even without factoring in the Xcel Energy reductions, these committed ongoing NOx reductions total over 5,000 tons/yr, over 50 times greater than the 87 tons/yr. at issue with Sappi Boiler No. 9. These emission reductions will further improve the visibility in the Class I areas, thus helping to ensure the trend remains below the URP.

3 Potential Visibility Improvement from Adding SNCR

3.1 Trajectory Analysis

The following information was included in the FFA report submitted by Sappi in July 2020 and is repeated here due to the relevance in determining if emission reductions from this facility will help make reasonable progress towards natural visibility on the most impaired days.

A trajectory analysis was conducted to provide insight as to the possible visibility impacts in the Boundary Waters due to emissions from Sappi. The Boundary Waters was selected as the closest Class I area.

A trajectory analysis considers the transport path of a particular air mass and the associated particles within the air mass to see if the air mass traveled over certain locations from specific source locations. The MPCA developed a tool[19] which calculates reverse trajectories from Class I areas in Minnesota for the “clearest” and “most impaired” days for 2007-2016 to help illustrate the influence of regional emissions on visibility. The reverse trajectories included in the MPCA tool were developed using the NOAA Hysplit model.[20] The trajectories consist of a single back trajectory for each “most impaired” day beginning at 18:00 and running back 48 hours with a starting height of 10 meters.

Barr completed an analysis to determine which of MPCA’s reverse trajectories from the Boundary Waters (BOWA1) monitor potentially crossed near Sappi to determine if the emissions

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[19] https://public.tableau.com/app/profile/mpca.data.services/viz/RegionalHaze_visibility_metrics_public/Visibilityprogress

[20] https://www.arl.noaa.gov/hysplit/hysplit/

from Sappi may have influenced the visibility on the "most impaired" days at the monitor. Figure 3.1 summarizes the number of "most impaired" trajectories for each year and season from 2014-2016 (the most recent year with data available on the MPCA website) and the corresponding number of "most impaired" trajectories that crossed near Sappi. The trajectories which crossed near Sappi are presented in Figure 3.2.

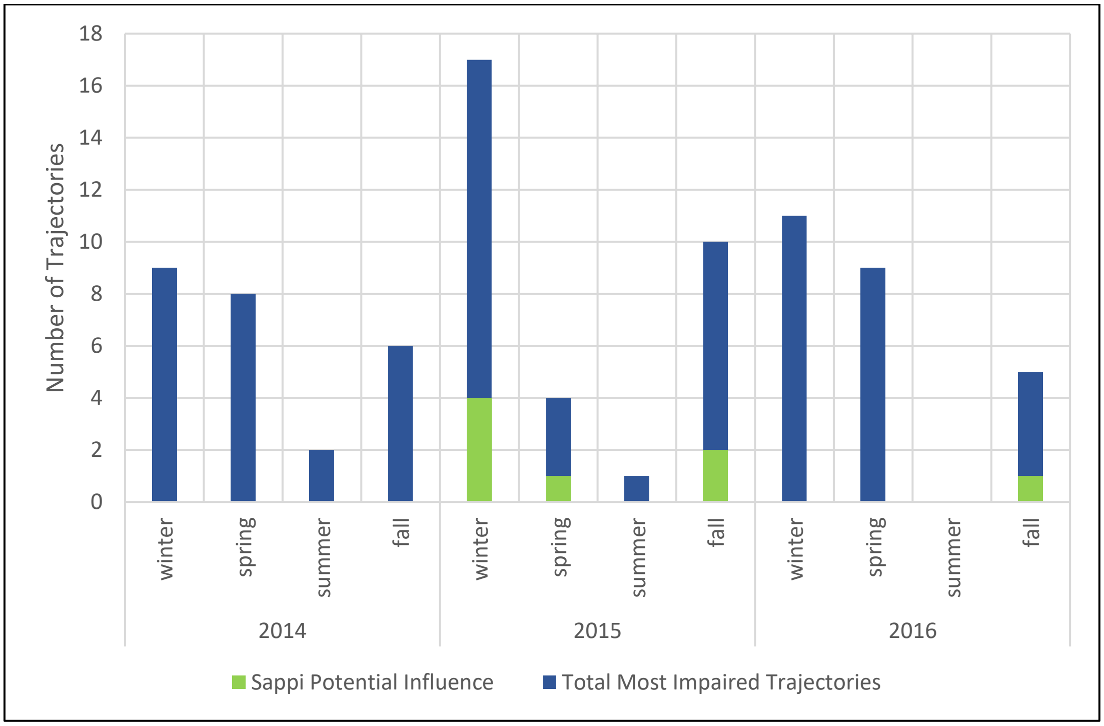

Figure 3.1: Total Number of Most Impaired Trajectories and Number that Cross Near Sappi for 2014-2016

Figure 3.2: Most Impaired Trajectories from MPCA Analysis that Cross Near Sappi in 2015-2016 (no trajectories cross near Sappi in 2014).

Based on the information provided in Figure 3.1, the number of trajectories originating from the Boundary Waters that cross near Sappi indicates that 84% of the time the trajectories did not cross near Sappi for the years analyzed (2014-2016). As expected, this percentage suggests that many sources and source regions other than Sappi are contributing to the visibility of the "most impaired" days at the monitor. Furthermore, the characterization of potential impacts is a conservative representation as the trajectory only had to cross within 20-30 miles of Cloquet to be included. Also, the majority of the origins of the reverse trajectories are well beyond the Sappi facility location and thus could have influences, depending on the trajectory, from a variety of other sources and from nearby cities such as Duluth, St. Cloud, Rochester, and the Twin Cities (Figure 3.2).

Based on the information provided above, we can conclude that emissions from Sappi are not a primary contributor to visibility impairment on the most impaired days at the Boundary Waters. Thus, additional control measures implemented at Sappi are unlikely to provide a substantial improvement in visibility in the Class I areas.

3.2 Emission Reductions Compared to Northern-Minnesota Sources

The installation of SNCR on Power Boiler #9 (EQUI 4) is expected to result in an emission reduction of 87 tons/year of NO_X which is just 0.15% of the total NO_X emissions in 2017 from the following counties in northern Minnesota which are closest to the Class I areas of concern:

- Cook
- Lake
- St. Louis
- Carlton
- Pine
- Aikin
- Crow Wing
- Cass
- Itasca
- Koochiching
- Beltrami
- Lake of the Woods
- Roseau

Since this emission reduction is such a small part of emissions in northern Minnesota, the impact on visibility from this single source will not result in a noticeable improvement in visibility.

3.3 Visibility Improvement Analysis

The potential visibility improvement from installing SNCR on Power Boiler #9 (EQUI 4) was estimated using USEPA MERPs screening techniques.[21] The MERPs guidance provides a model estimated concentration of $PM_{2.5}$ based on a given input rate. Using the MERPs Qlik tool, impacts to nearby Class I areas were derived, and scaled to provide the potential reduction in particulate concentrations associated with installing the controls.

From the estimated particulate mass associated with a potential 87 ton per year change in NO_2, Barr calculated the potential visibility impairment associated with that concentration using the second IMPROVE algorithm.[22] Conservatively assuming all resulting particulate reduction would be large nitrates, the net change in visibility impairment expected from those emissions was derived. Applying that change to the most recent data points yields a maximum of 0.031 dV benefit. Table 3-1 shows the potential improvements to visibility that would be associated with installing SNCR on Boiler #9 (EQUI 4). When reviewing this data, it is important to note that perceptible visual change in dV is generally accepted to fall in the range of 0.5 to 1.0 dV.[23]

While EPA guidance allows for a state to select sources for additional reductions based on thresholds lower than those of initial SIP implementation period best available retrofit technology (BART) analyses, the potential reduction impacts are an order of magnitude lower than those used for BART screening to determine whether a source significantly impacts a Class I area. Given existing monitored visibility levels are already below the targeted improvement for the 2028 target, applying controls to such a minimally contributing source is not necessary to aid in meeting reasonable progress, which is already being met. Furthermore, the current conditions are very nearly meeting the 2038 URP.

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[21] Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for O3 and PM2.5 under the PSD Permitting Program EPA-454/R-19-003, April 2019 (https://www.epa.gov/sites/default/files/2019-05/documents/merps2019.pdf)

[22] https://vista.cira.colostate.edu/Improve/the-improve-algorithm/

[23] 70 FR 39120 – the RHR preamble notes supporting views for both thresholds. Both are presented here for completeness The final rule cites 1.0 dV as 'causing' impairment and 0.5 dV as a ceiling for 'contributing' to impairment.

Table 3-1: Potential Visibility Improvement

Class I Area	Potential Reduction vs Most Impacted Days (dV)	Potential Reduction vs Clearest Days (dV)	2019 5-year Average Most Impacted Days (dV)[24]	2019 5-year Average Clearest Days (dV)[25]
BWCAW	0.012	0.031	13.4	4.2
Voyageurs	0.009	0.020	13.5	5.1
Isle Royale	0.009	0.023	14.7	5.1

4 Conclusions

Given visibility trends are already below the 2028 URP and additional reductions are expected from several major sources, reasonable progress is already being made for this period. Thus, MPCA's proposed cost effectiveness threshold of $10,000/ton NOx is not appropriate and the installation of SNCR on Power Boiler #9 (EQUI 4) is not cost effective. In addition, the emission reduction from this installation will not significantly reduce the total emissions in northern Minnesota nor will it result in a noticeable improvement in visibility in the Class I areas.

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[24] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

[25] Ibid.

Attachment A

Control Cost Calculations

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 430.0 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 4,597 Btu/lb

What is the estimated actual annual fuel consumption? 536,062,322 lbs/Year

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Lignite

Enter the sulfur content (%S) = 0.05 percent by weight

or Select

the appropriate SO_2 emission rate: < 3 lb/MMBtu

Ash content (%Ash): 2.8 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	352	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.292	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SNCR	0.219	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	3.02	

25.0% Control Efficiency

Plant Elevation 1083 Feet above sea level

Concentration of reagent as stored (C_{stored})	29	Percent
Density of reagent as stored (ρ_{stored})	56	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years

Densities of typical SNCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used Ammonia ▼

Enter the cost data for the proposed SNCR:

Desired dollar-year	2022			
CEPCI for 2022	776.3	Dec 2021 Final CEPCI value	541.7	2016 CEPCI
Annual Interest Rate (i)	5.5	Percent*		
Fuel ($Cost_{fuel}$)	1.94	\$/MMBtu*		
Reagent ($Cost_{reag}$)	0.56	\$/gallon for a 29 percent solution of ammonia (from USGS 01/2022)		
Water ($Cost_{water}$)	0.0042	\$/gallon*		
Electricity ($Cost_{elect}$)	0.0844	\$/kWh		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	48.80	\$/ton*		

CEPCI = Chemical Engineering Plant Cost Index

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) = 0.015
Administrative Charges Factor (ACF) = 0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.56/gallon of 29% Ammonia		U.S. Geological Survey, Minerals Commodity Summaries, 2021 https://pubs.usgs.gov/periodicals/mcs2022/mcs2022-nitrogen.pdf. $/gallon price was back calculated.
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0844		U.S. Energy Information Administration. Electric Power, January 2022 for MN industrial users. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
Fuel Cost ($/MMBtu)	1.94		U.S. Energy Information Administration. Electric Power Annual 2020. Table 7.4. Published March 2022. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.
Ash Disposal Cost ($/ton)	48.8	Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft Demand. July 11, 2017. Available at: http://www.wastebusinessjournal.com/news/wbj20170711A.htm.	
Percent sulfur content for Coal (% weight)	0.82	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Percent ash content for Coal (% weight)	13.60	Average ash content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	6,685	Select type of coal	
Interest Rate (%)	5.5	Default bank prime rate	

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	430	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	819,334,091	lbs/Year
Actual Annual fuel consumption (Mactual) =		536,062,322	lbs/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.00	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.631	fraction
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	5527	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	25	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	31.39	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	86.75	tons/year
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.07	
SO_2 Emission rate =	(%S/100)x(64/32)*(1x10^6)/HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.04	
Atmospheric pressure at 1083 feet above sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.1	psia
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	141	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/C_{sol} =	485	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	64.8	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	21,800	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1 =$ Where n = Equipment Life and i= Interest Rate	0.0837

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR =$	17.9	kW/hour
Water Usage: Water consumption (q_w) =	$(m_{sol}/\text{Density of water}) \times ((C_{stored}/C_{inj}) - 1) =$	110	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1) =$	1.14	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1x10^6)/HHV =$	6.9	lb/hour

Cost Estimate

Total Capital Investment (TCI)

TCI Provided by Updated 2022 Cost Estimates from Vendors

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =		
Total Capital Investment (TCI) =		

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$315,902	in 2022 dollars
Indirect Annual Costs (IDAC) =	$510,645	in 2022 dollars
Total annual costs (TAC) = DAC + IDAC	$826,547	in 2022 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$91,024	in 2022 dollars
Annual Reagent Cost =	$q_{sol} \times Cost_{reag} \times t_{op}$ =	$200,863	in 2022 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$8,327	in 2022 dollars
Annual Water Cost =	$q_{water} \times Cost_{water} \times t_{op}$ =	$2,544	in 2022 dollars
Additional Fuel Cost =	$\Delta Fuel \times Cost_{fuel} \times t_{op}$ =	$12,210	in 2022 dollars
Additional Ash Cost =	$\Delta Ash \times Cost_{ash} \times t_{op} \times (1/2000)$ =	$935	in 2022 dollars
Direct Annual Cost =		$315,902	in 2022 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	
Capital Recovery Costs (CR)=	CRF x TCI =	
Indirect Annual Cost (IDAC) =	AC + CR =	

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$826,547	per year in 2022 dollars
NOx Removed =	87	tons/year
Cost Effectiveness =	$9,528	per ton of NOx removed in 2022 dollars

Class 3 Estimate for SNCR System on #9 Boiler

	SNCR Installation for #9 Boiler	Cost Estimate
1	Equipment & Engineering (Jansen)	$2,271,000
3	Piping Labor (Jamar)	$601,302
4	Setting Skids & Tank Labor (Jamar)	$138,762
5	Install Steel Labor (Jamar)	$154,180
6	Install Tube Bends Labor (Jamar)	$231,270
7	Piping Tie-ins Labor (Jamar)	$231,270
8	Piping Relocations Labor (Jamar)	$154,180
9	Sheetmetal Flashing Labor (Jamar)	$30,836
10	Pipe Fitter Materials & Consumables (Jamar)	$166,462
11	Pipe Fitter Tools & Equipment (Jamar)	$178,738
12	Insulation (Jamar)	$83,750
13	Concrete Bases & Floor (Jamar)	$212,500
14	Scaffolding (Jamar)	$25,000
15	Refractory for Tube Bends (Jamar)	$9,372
16	Crane Rental (Jamar)	$191,670
17	Electrical Wiring Labor (Hunt)	$96,000
18	Electrical Wiring Materials (Hunt)	$51,000
19	Electrical Contingency (Hunt)	$15,300

20	Project Engineering (Sappi)	$484,259
21	Owners Cost (Sappi)	$257,159
25	Contingency	$484,259

Total	**$6,068,270**

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Fax: 425.825.1131
www.jansenboiler.com

March 8, 2022

Via E-mail

Mr. Erik Johnson
Sappi North America
2201 Avenue B
Cloquet, MN 55720

Re: Cloquet Mill - No. 9 Power Boiler
Letter Report Updating the Cost Estimate for a SNCR System
JANSEN Project No. 2022-0014

Dear Erik:

In September 2011, Jansen Combustion and Boiler Technologies, Inc. (JANSEN) provided a report to the Sappi Cloquet Mill titled ‘Definition Engineering and Class 10 Cost Estimate for the No. 9 Power Boiler SNCR System’ as the final deliverable for JANSEN project number 2011-0025. This report documented the computational fluid dynamics (CFD) modeling results for a selective non-catalytic reduction (SNCR) system for the No. 9 Power Boiler as well as provided a +/-10% budget cost estimate for the engineering, design, supply, and installation of an SNCR system.

Recently, Sappi has been requested by the Minnesota Pollution Control Agency (MPCA) to revise the budget cost estimate provided in 2011 to determine if a SNCR system is a viable method of controlling nitrogen oxides (NOx) emissions from the No. 9 Power Boiler.

This letter report is provided to update the original +/-10% budget cost estimate from 2011 to current cost in March of 2022. The scope of this revised cost estimate remains the same as that provided in September 2011 report ‘Definition Engineering and Class 10 Cost Estimate for the No. 9 Power Boiler SNCR System’ with the following clarifications:

- JANSEN’s original report included a cost estimate for the installation of the SNCR equipment. Sappi has requested a revised cost estimate directly from The Jamar Company for the installation of the SNCR equipment based on the information provided in the 2011 report. As a result, a revised installation cost estimate is not included in this letter report.

- All equipment is quoted FOB shop.
- The project schedule is estimated to require 10-12 months from notice to proceed to delivery of equipment.

Our revised budget cost estimate to provide the engineering, design, and equipment supply as described in our September 2011 report 'Definition Engineering and Class 10 Cost Estimate for the No. 9 Power Boiler SNCR System' is **$2,271,000**. This cost estimate excludes duties, taxes, shipping, or fees.

Thank you for the opportunity to be of service to the Sappi Cloquet Mill. Please contact us if you have any questions or require additional information. We look forward to working with Sappi in the future.

Sincerely,

Matthew A. Henderson, P.E.
Vice President, Design and Construction
Phone: 425.952.2844
E-mail: Matt.Henderson@jansenboiler.com

Paul W. Cloninger
Senior Mechanical Engineer
Phone: 425.952.2845
E-mail: Paul.Cloninger@jansenboiler.com

MAH/PWC:cjt

JAMAR®

THE JAMAR COMPANY | 4701 MIKE COLALILLO DR. | DULUTH, MN 55807-2762 | PHONE 218.628.1027 | FAX 218.628.1174

March 2, 2022

Sappi Fine Paper
2201 Avenue B
PO Box 511
Cloquet, MN 55720

Attn: Erik Johnson
Proposal: 22-I-1510
Subject: #9 Boiler SNCR System Installation

The Jamar Company proposes to furnish, as specified below, all the labor, material, tools, and equipment required to perform the subject project for a budgetary T&M price of **$2,409,292.00 (TWO MILLION FOUR HUNDRED NINE THOUSAND TWO HUNDRED NINETY-TWO DOLLARS)** which breaks down as follows:

Piping Labor	*2,400 man-hrs*	$ 601,302.00
Setting Skids & Tank Labor	*560 man-hrs*	$ 138,762.00
Install Steel Labor	*600 man-hrs*	$ 154,180.00
Install Tube Bends Labor	*960 man-hrs*	$ 231,270.00
Piping Tie-ins Labor	*960 man-hrs*	$ 231,270.00
Piping Relocations Labor	*600 man-hrs*	$ 154,180.00
Sheetmetal Flashing Labor	*150 man-hrs*	$ 30,836.00
Materials & Consumables		$ 166,462.00
Tools & Equipment		$ 178,738.00
Insulation		$ 83,750.00
Concrete Bases & Floor		$ 212,500.00
Scaffolding		$ 25,000.00
Refractory for Tube Bends		$ 9,372.00
Crane Rental		$ 191,670.00

1. Our proposal is based on **furnishing** the following:
    A. Installation of equipment skids and tank
    B. Installation of piping and required connections
    C. Installation of new steel and a monorail on the NW corner of 179’
    D. Modify the siding on 179’ for the monorail
    E. Installation of concrete bases for new skids and tank
    F. Supplying piping, fittings, hangers, steel, and concrete
    G. Installation of (4) single tube bends
    H. Insulation for #9 boiler for access to the tube bends
    I. Insulation for the outside portion of piping & new tank
    J. Scaffolding
    K. Refractory repairs around new tube bends

  L. Crane and operator
  M. Break trailer and portable restroom
  N. Subsistence

2. Our proposal is based on **excluding** the following:

   A. Any electrical, instrumentation or controls work
   B. Asbestos and lead abatement (by others)
   C. New equipment supply
   D. Boiler chemical cleaning
   E. Structural engineering
   F. Start-up assistance for the new system

3. Our proposal is based on the following general **exceptions and / or clarifications**:

   A. The pre-work is based on (4) pipefitters working a 10-hour shift per day, Monday through Friday, excluding Saturday, Sunday, and Holidays. The timeframe to complete all of the necessary pre-work piping is 4.5 months. The ironworkers and sheetmetal workers will complete their portion of work during this time. The outage is based on working a 12-hour shift per day, Monday through Friday, excluding Saturday, Sunday, and Holidays. The outage would require boilermakers and pipefitters.
   B. In the event, after acceptance of a purchase order, new tariffs or duties come into effect which impact the cost of materials included in the equipment or work supplied under this proposal, Jamar shall have the right to increase the overall price of such equipment or work to reflect the increased cost of such material to Jamar.
   C. Proposal is based on the information available to Jamar at the time of pricing; therefore, Jamar reserves the right to requote upon award and/or receipt of revised construction drawings and/or additional information.

4. Our proposal is based on working one (1) 10-hour shift per day, Monday through Friday, excluding Saturday, Sunday, and Holidays.

5. Our proposal is based on working under the National Maintenance Agreement.

6. Our proposal does not include work with or the removal or disposal of any hazardous material. Removal and disposal of hazardous material, required to complete specified work, is a customer / owner responsibility.

7. Our proposal does not include performance or payment bonds or permits.

8. Payment Terms: net 45 days *(note: all invoices not paid in 45 days will be charged 1½% interest per month on the unpaid balance as well as any fees incurred resulting from collection efforts)*.

9. Our proposal includes sales tax.

10. Our proposal is based upon the plans, specifications and scope as prepared by Erik Johnson and Jansen. A signed authorization to proceed must be provided prior to the performance of any additional work or change in project schedule or scope.

11. Additional work, performed by Jamar Company due to changes in out-of-scope items, will be performed on a lump sum or time and material basis, at your option.

12. Our proposal is based on working under the terms and conditions as contained in Sappi Contractor Agreement executed between Jamar and Sappi Cloquet LLC dated April 6, 2019.

13. Please incorporate the above terms into all related purchase orders and/or contracts.

We appreciate the opportunity to provide a quote for this project. If you should have any questions or require additional information, please feel free to contact me at (218) 206-5489.

Sincerely,
THE JAMAR COMPANY

David Swanson
Field Engineer

2022 CAPEX BUDGETARY PRICING

PB9 - SNCR INJECTION UPGRADES

Estimating take off sheet

03-14-2022 TJM

Description	Quanity	Cost	TOTAL MAT	LABOR	RATE	TOTAL LABOR
SAPPI					160	
Dual 30A fused disconect Mielke Quote #	4		8000	8		
Squasre D fused 30A LDS Graybar#	6		3000	24		
CONTRACTOR						
HEAT TRACE / CONTROLLER-LABOR			15000	64		
SNCR PLC CONTROL PANEL-MCC ROOM			4000	16		
FIBER-ETHERNET ?? TO SKIDS			12000	64		
STORAGE TANK POWER AND INST ELV 93'			2500	48		
LT-HV-AMMONIA MONITOR,GND						
STORAGE TANK INST.CONT ELV 93'						
LT-HV Ammonia MONITOR-GND			2500	48		
AA PUMP SYST SKID - ELV 93						
480v TO .5 HP PUMP			2500	48		
DILUTION WATER PUMP ELV.179'						
480V TO .5 hp PUMP PT, HV, GND			2500	48		
AA WATER METERING PUMP 179'						
480V TO PUMP, PT, FCV, GND			2500	48		
COOLING AIR SUPPLY-179'						
480V TO 7.5 hp SKID			2500	48		
AA INJECTION SYS 179'						
PWER AND INST			2500	48		
DCS INSTRUMENTATION			2500	80		
MOB/DEMOB -				8		
LABOR TOTAL				600	160	96000
MATERIAL TOTAL			51000			51000
30% CONTIGENCY			15300			15300
		BUDGETARY 2022 CAPEX PRICE				162300

Attachment B

MERPs Visibility Analysis Calculations

MERPs Summary

Calculated using 87 tpy NOx (2022)

Class I Area	Potential Reduction vs Most Impacted Days (dV)	Potential Reduction vs Clearest Days (dV)	2019 5-year Average Most Impacted Days	2019 5-year Average Clearest Days
BWCAW	0.012	0.031	13.4	4.2
Voyageurs	0.009	0.020	13.5	5.1
Isle Royale	0.009	0.023	14.7	5.1

MERPS emissions vs concentration data saved in "MERPS Qlik Table Export" tab. Data from Source: https://www.epa.gov/scram/merps-view-qlik 16MAR2022

Visibility values from IMPROVE data hosted by MPCA on https://public.tableau.com/app/profile/mpca.data.services/viz/RegionalHaze_visibility_metrics_public/Visibilityprogress

Conversion of MERPS air concentrations to visibility impairment using IMPROVE2 equation, as detailed on "About Visibility" tab on MPCA RH site.

Attachment B BWCAW MERPs Calculation

From MERPS Qlik calcs:

State	County	Distance	Metric	Precursor	Emissions	Stack	Concentration
Minnesota	St Louis	120	Daily PM2.5	NOx	500	90	0.019085

Source: https://www.epa.gov/scram/merps-view-qlik 16MAR2022

Potential reduction in NOx emissions from SNCR installation on Power Boiler #9

87	tons/year

0.00332	Equivalent change in PM2.5 concentration (ug/m3) scaled from MERPS Qlik value
	Second IMPROVE equation:
	bext ≈ 2.2 × fS(RH) × [Small Ammonium Sulfate] + 4.8 × fL(RH) × [Large Ammonium Sulfate] + 2.4 × fS (RH) × [Small Ammonium Nitrate] + 5.1 × fL(RH) × [Large Ammonium Nitrate] + 2.8 × [Small Organic Mass] + 6.1 × [Large Organic Mass] + 10 × [Elemental Carbon] + 1 × [Fine Soil] + 1.7 × fSS(RH) × [Sea Salt] + 0.6 × [Coarse Mass] + Rayleigh Scattering (Site Specific) + 0.33 × [NO2 (ppb)] Nitrate Effects Extracted from second IMPROVE equation: 2.4 × fS (RH) × [Small Ammonium Nitrate] + 5.1 × fL(RH) × [Large Ammonium Nitrate] Conservatively use the Large Nitrate values to give the greatest potential improvement per unit emissions 5.1 × fL(RH) × [Large Ammonium Nitrate]
2.78	fL(RH) for highest month in FLAG2010 guidance, Table 7 - September BOWA1 value = 2.78
14.178	IMPROVE weighting factor for Nitrate (per ug/m3)
0.0471	Calculated Change in visibility (bext) assuming entire emission reduction yields an equivalent reduction in Large Nitrate particulates

Attachment B

BWCAW MERPs Calculation

	From MPCA Tableau Regional Haze Summary (5-year IMPROVE averages) (https://public.tableau.com/app/profile/mpca.data.services/viz/RegionalHaze_visibility_metrics_public/Visibilityprogress)
13.4	2019 5yr average most impaired (in mmbext)
4.2	2019 5yr clearest (in mmbext)
38.190	2019 5yr average most impaired (in mmbext)
15.220	2019 5yr clearest (in mmbext)
	bext = 10*exp(DV/10) DV = 10*ln(bext/10); where bext is expressed in Mm-1.
0.012	Change in dV if reduction versus most impaired days background
0.031	Change in dV if reduction versus clearest days background

Attachment B Voyageurs MERPs Calculations

From MERPS Qlik calcs:

State	County	Distance	Metric	Precursor	Emissions	Stack	Concentration
Minnesota	St Louis	160	Daily PM2.5	NOx	500	90	0.014057

Source: https://www.epa.gov/scram/merps-view-qlik 16MAR2022

Potential reduction in NOx emissions from SNCR installation on Power Boiler #9

87	tons/year

0.00245	Equivalent change in PM2.5 concentration (ug/m3) scaled from MERPS Qlik value
	Second IMPROVE equation:
	bext ≈ 2.2 × fS(RH) × [Small Ammonium Sulfate] + 4.8 × fL(RH) × [Large Ammonium Sulfate] + 2.4 × fS (RH) × [Small Ammonium Nitrate] + 5.1 × fL(RH) × [Large Ammonium Nitrate] + 2.8 × [Small Organic Mass] + 6.1 × [Large Organic Mass] + 10 × [Elemental Carbon] + 1 × [Fine Soil] + 1.7 × fSS(RH) × [Sea Salt] + 0.6 × [Coarse Mass] + Rayleigh Scattering (Site Specific) + 0.33 × [NO2 (ppb)] Nitrate Effects Extracted from second IMPROVE equation: 2.4 × fS (RH) × [Small Ammonium Nitrate] + 5.1 × fL(RH) × [Large Ammonium Nitrate] Conservatively use the Large Nitrate values to give the greatest potential improvement per unit emissions 5.1 × fL(RH) × [Large Ammonium Nitrate]
2.7	fL(RH) for highest month in FLAG2010 guidance, Table 7 - September VOYA value = 2.70
13.77	IMPROVE weighting factor for Nitrate (per ug/m3)
0.0337	Calculated Change in visibility (bext) assuming entire emission reduction yields an equivalent reduction in Large Nitrate particulates

Voyageurs MERPs Calculations

	From MPCA Tableau Regional Haze Summary (5-year IMPROVE averages) (https://public.tableau.com/app/profile/mpca.data.services/viz/RegionalHaze_visibility_metrics_public/Visibilityprogress)
13.5	2019 5yr average most impaired (in mmbext)
5.1	2019 5yr clearest (in mmbext)
38.574	2019 5yr average most impaired (in mmbext)
16.653	2019 5yr clearest (in mmbext)
	bext = 10*exp(DV/10) DV = 10*ln(bext/10); where bext is expressed in Mm-1.
0.009	Change in dV if reduction versus most impaired days background
0.020	Change in dV if reduction versus clearest days background

Attachment B Isle Royale MERPs Calculations

From MERPS Qlik calcs:

State	County	Distance	Metric	Precursor	Emissions	Stack	Concentration
Minnesota	St Louis	260	Daily PM2.5	NOx	500	90	0.015185178

Source: https://www.epa.gov/scram/merps-view-qlik 16MAR2022

Potential reduction in NOx emissions from SNCR installation on Power Boiler #9

87	tons/year

0.00264	Equivalent change in PM2.5 concentration (ug/m3) scaled from MERPS Qlik value
	Second IMPROVE equation:
	bext ≈ 2.2 × fS(RH) × [Small Ammonium Sulfate] + 4.8 × fL(RH) × [Large Ammonium Sulfate] + 2.4 × fS (RH) × [Small Ammonium Nitrate] + 5.1 × fL(RH) × [Large Ammonium Nitrate] + 2.8 × [Small Organic Mass] + 6.1 × [Large Organic Mass] + 10 × [Elemental Carbon] + 1 × [Fine Soil] + 1.7 × fSS(RH) × [Sea Salt] + 0.6 × [Coarse Mass] + Rayleigh Scattering (Site Specific) + 0.33 × [NO2 (ppb)] Nitrate Effects Extracted from second IMPROVE equation: 2.4 × fS (RH) × [Small Ammonium Nitrate] + 5.1 × fL(RH) × [Large Ammonium Nitrate] Conservatively use the Large Nitrate values to give the greatest potential improvement per unit emissions 5.1 × fL(RH) × [Large Ammonium Nitrate]
2.82	fL(RH) for highest month in FLAG2010 guidance, Table 7 - September ISLE value = 2.82
14.382	IMPROVE weighting factor for Nitrate (per ug/m3)
0.0380	Calculated Change in visibility (bext) assuming entire emission reduction yields an equivalent reduction in Large Nitrate particulates

Attachment B

Isle Royale MERPs Calculations

	From MPCA Tableau Regional Haze Summary (5-year IMPROVE averages) (https://public.tableau.com/app/profile/mpca.data.services/viz/RegionalHaze_visibility_metrics_public/Visibilityprogress)
14.7	2019 5yr average most impaired (in mmbext)
5.1	2019 5yr clearest (in mmbext)
43.492	2019 5yr average most impaired (in mmbext)
16.653	2019 5yr clearest (in mmbext)
	bext = 10*exp(DV/10) DV = 10*ln(bext/10); where bext is expressed in Mm-1.
0.009	Change in dV if reduction versus most impaired days background
0.023	Change in dV if reduction versus clearest days background

sappi

Sappi North America

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UNITED STATES OF AMERICA
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www.sappi.com

Hassan Bouchareb
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155-4194

March 29, 2022

Re: Updated Cost Data and Information Related to SNCR for Boiler #9

Mr. Bouchareb:

As discussed, following our meeting on February 14, 2022, Sappi Cloquet LLC (Sappi) has obtained an updated cost estimate for the installation of Selective Non-Catalytic Reduction (SNCR) to control Nitrogen Oxides (NOx) on Boiler #9 at Sappi's Cloquet, Minnesota facility. Attached is a memorandum from Barr Engineering (Barr) discussing and providing the data. This data is also placed in the context of the potential effects of Boiler #9's emissions on the Class 1 areas.

These analyses and data show the following:

- Sappi's emissions *rarely* influence visibility at all in the Class 1 areas;
- When they do, they have *very low* impacts on visibility; and
- Installing SNCR on Boiler #9 is *very expensive* on a per-ton reduced basis.

Collectively, these three facts demonstrate that installing SNCR on Boiler #9 is *not* cost-effective under applicable law and guidance, and it would be arbitrary, capricious, and contrary to law for either MPCA or EPA to attempt to require Sappi to do so.

Specifically, Barr prepared a trajectory analysis to accompany Sappi's Four Factor Analysis in 2020. This looked at trajectories over three years (2014-2016) on the most impaired days, and focused on the closest Class 1 area, the BWCAW. The review showed that Sappi's emissions did not influence visibility on *any* most-impaired day in 2014, and influenced visibility on only seven days in 2015, and on only one day in 2016. Overall, on 84% of the most-impaired days over this three year period, Sappi's emissions had no influence. *See* 2020 Four Factor Analysis at § 5.2. The MPCA has not disputed the accuracy of this analysis.

On the rare occasions when Sappi's emissions have any influence, it is extremely small. As explained in the Barr Memo, Sappi's emissions, with conservative assumptions, top out at a maximum of 0.031 dV benefit – more than an order of magnitude below the threshold that EPA views as "contributing" to impairment.

Sappi is well aware that visibility impairment can arise from the collective interaction of many small contributors, but Sappi's very low degree of influence on visibility conditions is clearly relevant to assessing whether additional controls are cost-effective. The updated cost estimates show that, prior to any adjustments for frequency and significance of impacts, the cost of SNCR of nearly $10,000/ton is not cost-effective standing alone. And once the lack of influence is factored in, there can be no reasonable dispute that SNCR is unjustified on cost-effectiveness grounds.

We look forward to further discussions on the topic on March 31.

Sincerely,

Tom Radovich P.G.

Tom Radovich
Managing Director
Cloquet Operations

--- submitted electronically ---

MINNESOTA POLLUTION
CONTROL AGENCY

520 Lafayette Road North | St. Paul, Minnesota 55155-4194 | 651-296-6300
800-657-3864 | Use your preferred relay service | info.pca@state.mn.us | Equal Opportunity Employer

February 14, 2020

Derwood Brady, Vice President
Southern Minnesota Beet Sugar Coop
83550 County Road 21
Renville, MN 56284

RE: Request for Information - Regional Haze Rule, Reasonable Progress, Four Factor Analysis

Dear Mr. Brady:

The Minnesota Pollution Control Agency (MPCA) is currently preparing information for the second planning period (Round 2) comprehensive update to Minnesota's Regional Haze State Implementation Plan (SIP) as required by the Regional Haze Rule (40 CFR § 51.308). States are responsible for developing a Regional Haze SIP that addresses regional haze in each Class I area located within the state and in each Class I area located outside the state which may be affected by emissions from sources within the state. The Regional Haze SIP is required to identify existing facilities that cause or contribute to visibility impairment; analyze, identify, and apply federally-enforceable control strategies for those sources; and periodically demonstrate reasonable progress toward reaching visibility goals. States are also responsible for periodic comprehensive updates to their Regional Haze SIP that address these same topics. Minnesota's Round 2 Regional Haze SIP must be submitted to the U.S. Environmental Protection Agency (U.S. EPA) by July 31, 2021.

Minnesota has two Class I areas within its borders, the Boundary Waters Canoe Area Wilderness (BWCA) and Voyageurs National Park (Voyageurs). Other nearby Class I areas include Isle Royale National Park in Michigan. Therefore, Minnesota must prepare a Regional Haze SIP that identifies sources that cause or contribute to visibility impairment in these areas. To meet the core requirements for regional haze for these areas, Minnesota must submit a SIP that contains the plan elements and supporting documentation for all required analyses identified in 40 CFR § 51.308(f).

In the first planning period (Round 1), the focus of the Regional Haze Rule was on establishing Best Available Retrofit Technology (BART) for certain older sources and reasonable progress towards national visibility goals. In Round 2, there are no BART requirements; therefore, the focus is on making reasonable progress. The U.S. Environmental Protection agency has defined the methodology that states must use to determine what measures are necessary to make reasonable progress in 40 CFR § 51.308(f)(2). At minimum, the reasonable progress analysis must use the four factors identified in 40 CFR § 51.308(f)(2)(i) to evaluate and determine the emission reduction measures necessary to make reasonable progress. The four factors are:

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

Data from the IMPROVE monitoring sites at BWCA and Voyageurs indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X).

You are receiving this letter because your facility was identified as a significant source of NO_X and SO_2 and is located close enough to the BWCA or Voyageurs to potentially cause or contribute to visibility impairment in these Class I areas. Therefore, the MPCA requests that you prepare a "Four Factor Analysis" for the following emission units:

1. Boiler No. 1 (EQUI 17 / EU 001) that addresses emissions of NO_X and SO_2

The analysis should be prepared using the U.S. Environmental Protection Agency guidance[1] that provides recommendations for how each of the factors should be determined.

Preparation of the comprehensive update to Minnesota's Regional Haze SIP will require extensive planning and review of sources in Minnesota. The MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to prepare the Regional Haze SIP. The MPCA expects air quality modeling of potential regional emissions reductions will be conducted beginning in spring 2020. I appreciate your attention to this matter and request that you **submit the Four Factor Analysis by July 31, 2020**.

If you have any questions regarding this matter, or would like to request a meeting to further discuss the contents of this letter, please contact me by phone at 651-757-2653 or by email at Hassan.Bouchareb@state.mn.us.

Sincerely,

Hassan Bouchareb

This document has been electronically signed.

Hassan M. Bouchareb
Engineer
Environmental Analysis and Outcomes Division

Cc: Deepa de Alwis, MPCA
Cory Boeck, MPCA
Frank Kohlasch, MPCA
Agency Interest ID 1682

Address questions and submittals requested above to:

Hassan M. Bouchareb
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155-4194
(651) 757-2653
Hassan.Bouchareb@state.mn.us

---

[1] **U.S. Environmental Protection Agency.** *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 20, 2019, https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

Regional Haze Four-Factor Analysis for NOx and SO2 Emissions Control

Boiler No. 1 (EQUI17)

Prepared for
Southern Minnesota Beet Sugar Cooperative

July 31, 2020

325 South Lake Avenue
Duluth, MN 55802
218.529.8200
www.barr.com

Regional Haze Four-Factor Analysis for NO_x and SO_2 Emissions Control

July 31, 2020

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Appendix A: Control Cost Analysis for NOx and SO_2

Abbreviations

ACF	Annual Capacity Factor
BART	Best Available Retrofit Technology
BWCA	Boundary Waters Canoe Area
CEMs	Continuous Emission Monitoring System
CEPCI	Chemical Engineering Plant Cost Index
CPI	Consumer Price Index
DSI	Dry Sorbent Injection
GCVTV	Grand Canyon Visibility Transport Commission
IMPROVE	Interagency Monitoring of Protected Visual Environments
LADCO	Lake Michigan Air Directors Consortium
LNB	Low-NOX Burners
MPCA	Minnesota Pollution Control Agency
nonEGU	Non-Electric Generating Unit
NOx	Nitrogen Oxides
O&M	Operations and Maintenance
OFA	Overfire Air
RFI	Request for Information
RHR	Regional Haze Rule
SCC	Source Classification Code
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
SDA	Spray Dryer Absorber
SIP	State Implementation Plan
SMBSC	Southern Minnesota Beet Sugar Cooperative
SO_2	Sulfur Dioxide
TPY	Ton per Year
URP	Universal Rate of Progress
USEPA	U.S. Environmental Protection Agency

1 Executive Summary

In accordance with Minnesota Pollution Control Agency's (MPCA's) January 29, 2020, Request for Information (RFI) Letter[1], Southern Minnesota Beet Sugar Cooperative (SMBSC) evaluated potential emission control measures for sulfur dioxide (SO_2) and nitrogen oxides (NO_X) for Boiler No. 1 as part of the State's Regional Haze Rule (RHR)[2] reasonable progress. The analysis considers potential emissions control measures by addressing the four statutory factors laid out in 40 CFR 51.308(f)(2)(i) and pursuant to the final EPA RHR State Implementation Plan (SIP) guidance[3] on August 20, 2019 (2019 RH SIP Guidance):

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

This report describes the background and analysis for conducting the four-factor analysis for NO_x and SO_2 as applied to the review of emissions controls for the coal-fired boiler at SMBSC. The four-factor analysis conclusions are summarized in Table 1-1 and Table 1-2 for NO_x and SO_2, respectively.

The NO_x four-factor analysis evaluated the following NO_x emissions control measures:

- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)
- Low NO_x Burners (LNB)
- Low NO_x Burners with Over Fire Air (LNB+OFA)

In the Factor 1 – Cost of Compliance analysis, the associated cost effectiveness ($ for each ton of emissions reduction) for each of the evaluated technologies exceeded the range of cost effectiveness that was stated in the EPA's Final Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS for NOx emission controls (refer to Sections 4.2 and 5.2 for more information). Therefore, none of the potential NO_x emission control measures are reasonable for installing on SMBSC's Boiler 1.

The SO_2 four-factor analysis evaluated the following SO_2 emissions reduction technologies:

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[1] February 14, 2020 letter from Hassan Bouchareb of MPCA to Derwood Brady of Southern Minnesota Beet Sugar Cooperative

[2] The U.S. Environmental Protection Agency (EPA) also refers to this regulation as the Clean Air Visibility Rule. The regional haze program requirements are promulgated at 40 CFR 51.308. The SIP requirements for this implementation period are specified in §51.308(f).

[3] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003.

- Spray Dryer Absorption (SDA)
- Dry Sorbent Injection (DSI)

In the Factor 1 – Cost of Compliance analysis, the associated cost effectiveness ($ for each ton of emissions reduction) for each of the evaluated technologies far exceeded the range of cost effectiveness in the MPCA's original BART SO_2 cost thresholds (refer to Sections 4.2 and 6.1.1 for more information). Therefore, none of the potential SO_2 emission control measures are reasonable for installing on SMBSC's Boiler 1.

In addition to the four statutory factors, this analysis evaluates the resulting visibility improvements from the emission control measures, which is referred to as the "fifth factor" (refer to Section 7.0 for more information). The results of the analysis conclude that SMBSC provides virtually no contribution to visibility impairment at the Upper Midwest Class I areas. Thus, additional control measures implemented at SMBSC are unlikely to provide improvement in visibility in those areas.

Table 1-1: Summary of NO_x Four-Factor Analysis

List of Emission Control Measures	Factor 1 Cost of Compliance	Factor 2 Time Necessary for Compliance	Factor 3 Energy and Non Air Quality Environmental Impacts of Compliance	Factor 4 Remaining Useful Life of the Source
Selective Catalytic Reduction with Reheat	$7,000/ton	2-3 years	Additional electricity and natural gas consumption for reheat	20 years
Low NO_x Burners	$5,100/ton	2-3 years	Reduced Thermal Efficiency	20 years
Low NO_x Burners with Over Fire Air	$3,600/ton	2-3 years	Reduced Thermal Efficiency	20 years
Selective Non-Catalytic Reduction	$3,800/ton	2-3 years	Additional electricity to operate equipment Additional fuel to evaporate water in the injected reagent Additional waste generated due to increased fuel consumption	20 years

Table 1-2: Summary of SO_2 Four-factor Analysis

List of Emission Control Measures	Factor 1 Cost of Compliance	Factor 2 Time Necessary for Compliance	Factor 3 Energy and Non Air Quality Environmental Impacts of Compliance	Factor 4 Remaining Useful Life of the Source
Spray Dry Absorber with baghouse	$16,600/ton	2-3 years	Additional electricity use to operate equipment Solid waste disposal for spent sorbent and baghouse bags	20 years
Dry Sorbent Injection	$12,700/ton	2-3 years	Additional electricity use to operate equipment Solid waste disposal for spent sorbent and baghouse bags	20 years

2 Introduction

This section discussed the pertinent regulatory background information and a description of SMBSC's coal-fired boiler.

2.1 Four-factor Analysis Regulatory Background

The RHR published on July 15, 2005, by the U.S. Environmental Protection Agency (EPA), defines regional haze as "visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources." The RHR requires state regulatory agencies to submit a series of state implementation plans (SIPs) in ten-year increments to protect visibility in certain national parks and wilderness areas, known as mandatory Federal Class I areas. The original State SIPs were due on December 17, 2007, and included milestones for establishing reasonable progress towards the visibility improvement goals, with the ultimate goal to achieve natural background visibility by 2064. The original SIP was informed by best available retrofit technology (BART) analyses that were completed on all subject-to-BART sources. The second RHR planning period requires development and submittal of updated state SIPs by July 31, 2021.

On February 14, 2020, the MPCA sent an RFI to SMBSC. The RFI stated that data from the Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring sites at Boundary Waters Canoe Area (BWCA) and Voyageurs National Park (Voyageurs) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of SO_2 and NO_x. In addition, emissions from sources in Minnesota could potentially impact Class I areas in nearby states, namely Isle Royale National Park (Isle Royale) in Michigan. Although Michigan is responsible for evaluating haze in Isle Royale, they must consult with surrounding states, including Minnesota, on potential cross-state haze pollution impacts. As part of the planning process for the SIP development, MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to evaluate regional emission reductions.

The RFIs also stated that the facility was identified as a significant source of NO_x and SO_2 that is located close enough to the BWCA and Voyageurs to potentially cause or contribute to visibility impairment. Therefore, the MPCA requested that SMBSC submit a "four factors analysis" (herein termed as a four-factor analysis) by July 31, 2020 for the emission units identified in Table 1 as part of the State's regional haze reasonable progress.

Table 2-1: Identified Emission Units

Unit	Unit ID	Applicable Pollutants
Boiler No. 1	EQUI17	NO_x & SO_2

The analysis considers potential emissions reduction measures by addressing the four statutory factors which are laid out in 40 CFR 51.308(f)(2)(i):

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

The RFI letter to the SMBSC specified that the "… analysis should be prepared using the U.S. Environmental Protection Agency guidance" referring to the final 2019 RH SIP Guidance.[3]

This report describes the background and analysis for conducting a four-factor analysis for NO_x and SO_2 as applied to the review of emissions controls at SMBSC for the unit identified in Table 2-1.

2.2 Facility Description

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 (EQUI 17) is a Babcock and Wilcox (B&W) Stirling boiler installed in 1975. The boiler fires sub-bituminous coal as the primary fuel source and is controlled by a high-efficiency electrostatic precipitator (TREA 14) for particulate emissions. The flue gas from the electrostatic precipitator is routed to a single stack (STRU 25). The boiler is monitored by a continuous opacity monitor (COM) and continuous emissions monitors (CEMs) for NO_x, SO_2, and O2.

Figure 2-1 shows a schematic representation of Boiler 1.

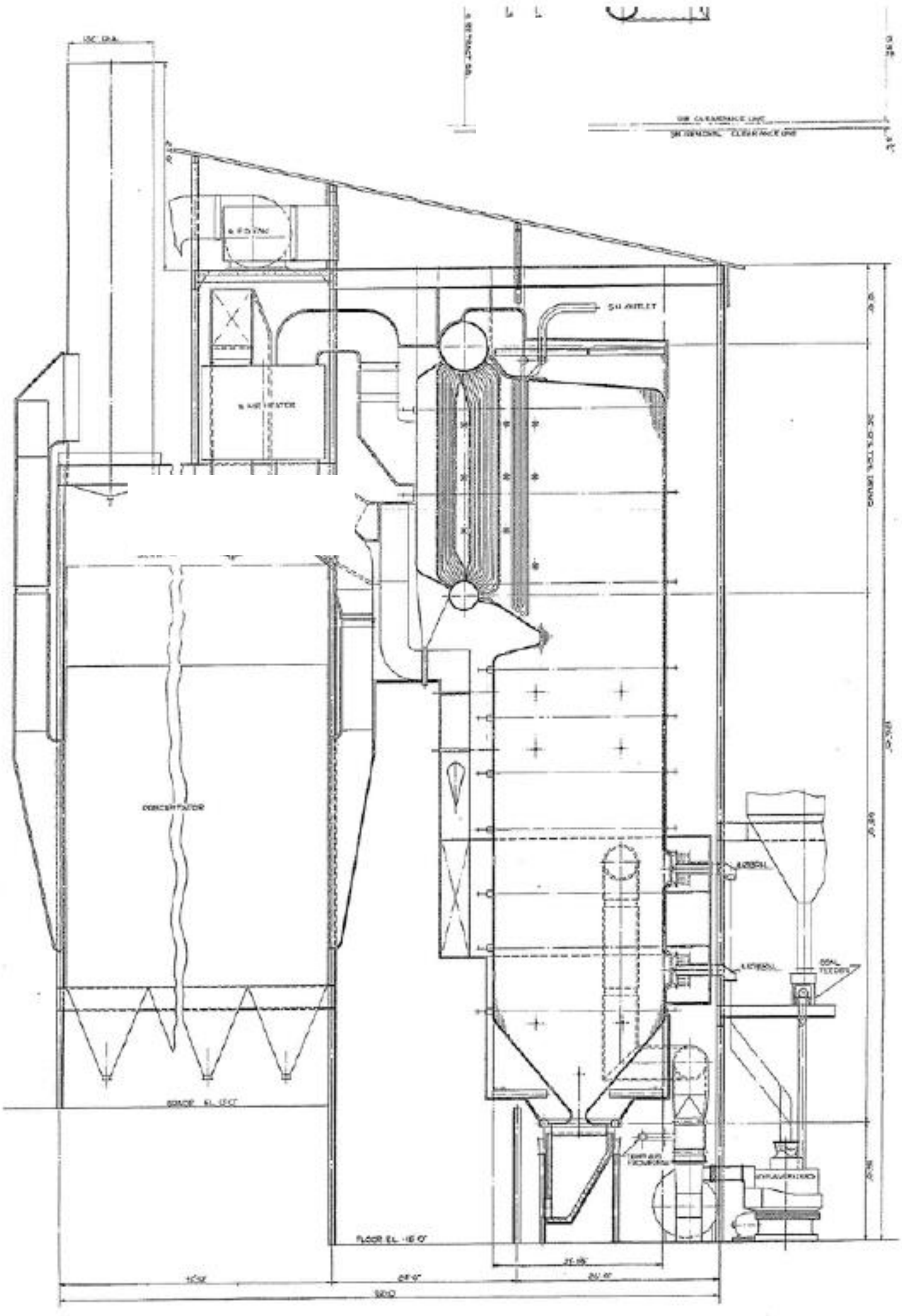

Figure 2-1: Boiler 1 Schematic

3 Existing Controls and Baseline Emission Performance

This section describes the existing NO_x and SO_2 emissions controls, and the baseline emissions to evaluate the cost effectiveness for the associated emission reduction technologies.

3.1 Existing Emission Controls

SMBSC's Boiler 1 is equipped with an electrostatic precipitator that controls particulate matter. There is no control equipment currently installed on the boiler for SO_2 or NO_x control.

3.2 Baseline Emissions Performance

The four-factor analysis requires the establishment of a baseline scenario for evaluating a potential emission control measure. At page 29 in the section entitled "Baseline control scenario for the analysis," excerpted below, EPA considers the projected 2028 emissions scenario as a "reasonable and convenient choice" for the baseline control scenario:

> "Typically, a state will not consider the total air pollution control costs being incurred by a source or the overall visibility conditions that would result after applying a control measure to a source but would rather consider the incremental cost and the change in visibility associated with the measure relative to a baseline control scenario. The projected 2028 (or the current) scenario can be a reasonable and convenient choice for use as the baseline control scenario for measuring the incremental effects of potential reasonable progress control measures on emissions, costs, visibility, and other factors. A state may choose a different emission control scenario as the analytical baseline scenario. Generally, the estimate of a source's 2028 emissions is based at least in part on information on the source's operation and emissions during a representative historical period. However, there may be circumstances under which it is reasonable to project that 2028 operations will differ significantly from historical emissions. Enforceable requirements are one reasonable basis for projecting a change in operating parameters and thus emissions; energy efficiency, renewable energy, or other such programs where there is a documented commitment to participate and a verifiable basis for quantifying any change in future emissions due to operational changes may be another. A state considering using assumptions about future operating parameters that are significantly different than historical operating parameters should consult with its EPA Regional office."

The 2016 and 2028 non-electric generating unit (nonEGU) inventory from EPA was used to determine baseline emissions from Boiler 1 to be used in the four factor analysis. This was acquired from the EPA and confirmed to be accurate by the MPCA. The 2016 modeled emissions align with SMBSC's CEMs data reported to the MPCA. Boiler 1 has a projection factor from 2016 to 2028 of 0.9756 based on coal-fired, non-utility boilers in Minnesota (i.e., not just SMBSC Boiler 1). This represents a 2.5% decrease in emissions from 2016 when projecting forward to 2028 (roughly 0.2% per year). Source classification codes (SCC) beginning with "102002" were projected using this factor. Specifically, this projection factor was used for SMBSC and other beet sugar processing plant boilers. Table 3-2 provides the 2016 and 2028 baseline emissions. The four-factor analysis uses the 2028 emissions.

Table 3-2: 2016 and 2028 EPA Modeling Emissions Inventory for SMBSC Sources (TPY)

Units	2016 SO_2	2028 SO_2	2016 NO_x	2028 NO_x
Boiler 1	805	786	930	907

4 Four-factor Analysis Overview

This section summarizes the four-factor analysis approach with respect to the Regional Haze program detailed in the 2019 RH SIP guidance.

4.1 Emission Control Options

Prior to completing a four-factor analysis of each emission control measure, all commercially available and technically feasible emission control options for the coal-fired boiler must first be identified. Potentially available emission control options include both add-on control equipment and process improvement applications. All control options identified as available and technically feasible are then evaluated against the "four factors."

In order to be considered available and technically feasible, an emission control measure must have been previously installed and operated successfully on a similar source under similar physical and operating conditions. Novel controls that have not been demonstrated on full-scale, industrial operations are not considered as part of this analysis. Instead, this evaluation focuses on commercially demonstrated control options.

An evaluation of the commercially available and technically feasible control measures for NO_x and SO_2 are discussed in Sections 5.1 and 6.1, respectively.

4.2 Factor 1 – Cost of Compliance

Factor #1 considers and estimates, as needed, the capital and annual operating and maintenance (O&M) costs of the control measure. As directed by the 2019 RH SIP Guidance at page 21, costs of emissions controls follow the accounting principles and generic factors from the EPA Air Pollution Control Cost Manual (EPA Control Cost Manual)[4] unless more refined site-specific estimates are available. Under this step, the annualized cost of installation and operation on a dollars per ton of pollutant removed ($/ton) of the control measure, referred to as "average cost effectiveness," is compared to a cost effectiveness threshold that is estimated by the MPCA.

Generally, if the average cost effectiveness is greater than the threshold, the cost is considered to not be reasonable, pending an evaluation of other factors. Conversely, if the average cost effectiveness is less than the threshold, then the cost is considered reasonable for purposes of Factor #1, pending an evaluation of whether the absolute cost of control (i.e., costs in absolute dollars, not normalized to $/ton) is unreasonable.

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[4] US EPA, "EPA Air Pollution Control Cost Manual, Sixth Edition," January 2002, EPA/452/B-02-001. The EPA has updated certain sections and chapters of the manual since January 2002. These individual sections and chapters may be accessed at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution as of the date of this report.

The cost of an emissions control measure is derived using capital and annual operation and maintenance (O&M) costs. Capital costs generally refer to the money required to design and build the system. This includes direct costs, such as equipment purchases, and installation costs. Indirect costs, such as engineering and construction field expenses and lost revenue due to additional unit downtime in order to install the additional control measure(s), are considered as part of the capital calculation. Annual O&M costs include labor, supplies, utilities, etc., as used to determine the annualized cost in the numerator of the cost effectiveness value. The denominator of the cost effectiveness value (tons of pollutant removed) is derived as the difference in: 1) projected emissions using the current emissions control measures (baseline emissions), as described in Section 3.2, in tons per year (tpy), and 2) expected annual emissions performance through installation of the additional control measure (controlled emissions), also in tpy.

For purposes of calculating cost effectiveness, SMBSC uses the updated baseline emissions value of 235 lb NO_x /hr and 196 lb SO_2/hr, as described in Section 3.2, in conjunction with projected hours of operation of the unit to determine an annual tpy value. SMBSC assumes 7,536 operating hours per year based on the past five years of operation. SMBSC considers this value representative of projected operations for purposes of determining annualized emissions. The product of the 235 and 196 lb/hr values and projected operating hours converted to a tpy basis is 886 tpy NO_x and 738 tpy SO_2 and for each unit as the baseline annual emissions rate to be used for purposes of determining annual emissions reductions for a given additional control measure.

The calculated cost effectiveness value for each control measure is compared to a cost effectiveness threshold established by the MPCA or the EPA. The MPCA's original BART SO_2 cost thresholds were based on the "high cost" value of $3,000 per ton, listed in the June 1999 WRAP Annex to Grand Canyon Visibility Transport Commission (GCVTC) Report.[5] This 1999 value is scaled to today's dollars using the Chemical Engineering Plant Cost Index (CEPCI).[6] The CEPCI is an industrial plant index that is considered more representative for purposes of this analysis than general cost indices such as the Consumer Price Index (CPI). The average cost effectiveness threshold in current dollars is calculated to be $5,600 per ton for SO_2. The average cost effectiveness threshold for NO_x is based on the EPA's Final Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS[7] which provides a cost effectiveness

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[5] Cited by EPA in the "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations" proposed rule; 69 FR 25198; May 5, 2004.

[6] More information on CEPCI may be found at this link: https://www.chemengonline.com/pci-home. The CEPCI is accessible by subscription through "Chemical Engineering" magazine. The CEPCI scaling factors for this analysis compare 1999 values to January 2020 values.

[7] The EPA's Final Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS[7] may be found online at this link: https://www.epa.gov/sites/production/files/2017-05/documents/final_assessment_of_non-egu_nox_emission_controls_cost_of_controls_and_time_for_compliance_final_tsd.pdf

value of $2,400 per ton for NO_x control on a coal-fired boiler. This 2011 value scaled to today's dollars using CEPCI, is $3,100 per ton of NO_x.

4.3 Factor 2 – Time Necessary for Compliance

Factor #2 is considered by MPCA in setting reasonable deadlines for the selected control. This includes the planning, installation, and commissioning of the selected control.

For purposes of this analysis and if a given NO_x or SO_2 control measure requires a unit outage as part of its installation, SMBSC considers the forecasted outage schedule for the associated units in conjunction with the expected timeframe for engineering and equipment procurement following MPCA and EPA approval of the given control measure.

4.4 Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance

Factor #3 involves consideration of the energy and non-air environmental impacts of each control measure. Non-air quality impacts may include solid or hazardous waste generation, wastewater discharges from a control device, increased water consumption, and land use. The environmental impact analysis is conducted based on consideration of site-specific circumstances.

The energy impact analysis considers whether use of an emissions control measure results in any significant or unusual energy penalties or benefits. Energy use may be evaluated on energy used per unit of production basis; energy used per ton of pollutant controlled or total annual energy use.

4.5 Factor 4 – Remaining Useful Life of the Source

Factor #4 is the remaining useful life of the source, which is the difference between the date that additional emissions controls will be put in place and the date that the facility permanently ceases operation. Generally, the remaining useful life of the source is assumed to be longer than the useful life of the emissions control measure unless there is an enforceable cease-operation requirement. In the presence of an enforceable end date, the cost calculation can use a shorter period to amortize the capital cost.

For the purpose of this evaluation, the remaining useful life for the unit is assumed to be longer than the useful life of the additional emission control measures. Therefore, the expected useful life of the control measure is used to calculate the emissions reductions, amortized costs, and the resulting cost per ton ($/ton).

5 NO_x Four-factor Analysis

This section identifies and describes various NO_x emission control measures, evaluates the four statutory factors for Boiler 1. Consistent with EPA's guidance and MPCA direction, SMBSC has completed a four-factor analysis for NO_x as summarized in Sections 5.1 to 5.5.

5.1 NO_x Control Measures Overview

There are three mechanisms by which NO_x production occurs. They are thermal, fuel, and prompt NO_x formation.

In the case of natural gas combustion, the primary mechanism of NO_x production is through thermal NO_x formation. This mechanism arises from the thermal dissociation of nitrogen and oxygen molecules in combustion air to nitric oxide (NO). The thermal oxidation reaction is as follows:

$$N_2 + O_2 \rightarrow 2NO \qquad (1)$$

Downstream of the flame, significant amounts of NO_2 can be formed when NO is mixed with air. The reaction is as follows:

$$2NO + O_2 \rightarrow 2NO_2 \qquad (2)$$

Thermal oxidation is a function of the residence time, free oxygen, and peak reaction temperature.

Prompt NO_x is a form of thermal NO_x which is generated at the flame boundary. It is the result of reactions between nitrogen and hydrocarbon radicals generated during combustion. Only minor amounts of NO_x are emitted as prompt NO_x.

Fuel bound NO_x is primarily a concern with solid and liquid fuel combustion sources; it is formed as nitrogen compounds in the fuel are oxidized in the combustion process.

Several techniques can be used to reduce NO_x emissions from coal-fired boilers, as listed in Table 5-1.

Table 5-1: Additional NO_x Emission Control Measures with Potential Application at Coal-Fired Boilers

Emission Control Measures
Low- NO_x *Burners (LNB)*
Low- NO_x *Burners with Over Fired Air (LNB+OFA)*
Post-Combustion Controls • *Non-Selective Catalytic Reduction (NSCR)* • *Selective Catalytic Reduction (SCR)*

The following Sections 5.1.1 through 5.1.4 describes aspects of each emission control measure determined to be feasible for coal-fired boilers.

5.1.1 Low- NO_x Burners (LNB)

LNB technology utilizes advanced burner design to reduce NO_x formation through the restriction of oxygen, flame temperature, and/or residence time. LNB technology is a staged combustion process that is designed to split fuel combustion into two zones. In the primary zone, NO_x formation is limited by either one of two conditions; rich or lean fuel. Under a rich (high fuel) condition, oxygen levels and flame temperatures are low resulting in less NO_x formation. The primary zone is then followed by a secondary zone in which the incomplete combustion products formed in the primary zone act as reducing agents.

LNB technology reduces the formation of NO_x during fuel combustion, rather than remove it after formation as do other control devices. LNB are more reliable than other control devices because there are no added pieces of equipment to operate, maintain, or malfunction. LNB do not use additional electricity, nor do they generate any wastewater or solid waste streams. They do have the disadvantage that they are not as thermally efficient as standard burners when considering only the thermal requirements and not considering the overall energy (thermal and electrical) as compared to a standard burner technology and the electricity used by a control device and the treatment of wastewater and solid waste disposal.

5.1.2 Low NO_x Burners with Overfire Air (LNB+OFA)

Low NO_x burners with overfire air utilize the same LNB technology described in Section 5.1.1 with the addition of overfire air. The addition of OFA diverts combustion air away from the primary combustion zone to a location above the highest burner. The overfire air maintains a lower temperature to prevent the formation of thermal NO_x as well as providing oxygen to complete the combustion reaction.

A Low NO_x burner with overfire air is a reliable emission control option with no added piece of equipment to operate, maintain, or malfunction. The addition of over-fire air also does not create any additional electricity or waste costs.

5.1.3 Selective Catalytic Reduction (SCR)

SCR is a post combustion NO_x control measure in which ammonia (NH_3) or urea (CH_4N_2O) is injected into the flue gas stream in the presence of a catalyst. SMBSC evaluated urea injection, which converts to ammonia after injection into the flue gas. SCR control efficiency is typically 70 to 90 percent. SCR requires an optimum temperature range of 570°F to 850°F. Figure 2-1 is a diagram of SCR catalyst activity vs. temperature from Section 4, Chapter 4 from the EPA Air Pollution Control Cost Manual - Sixth Edition (EPA 452/B-02-001)

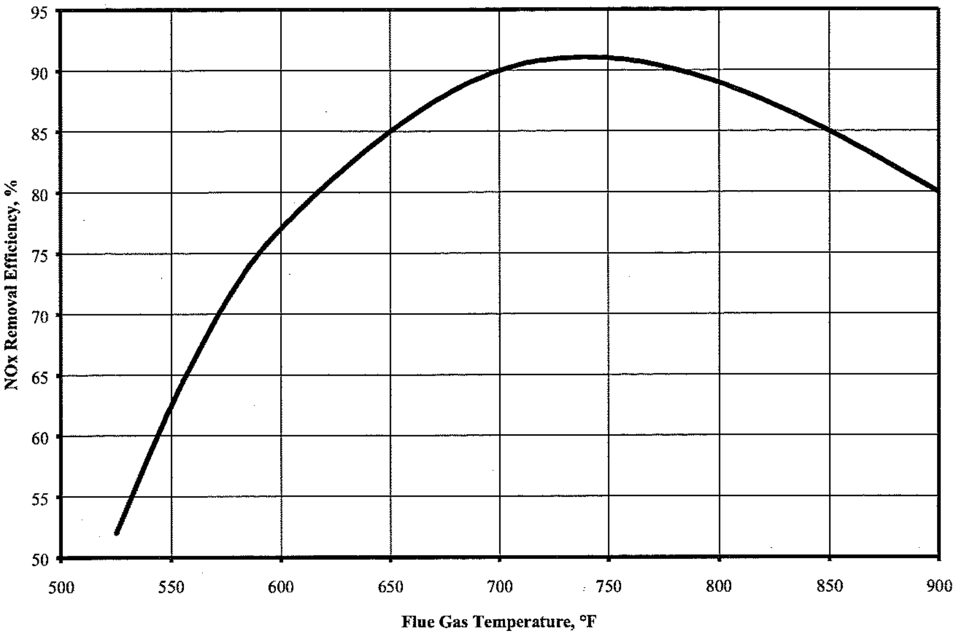

Figure 5-1: NO_X Removal using SCR vs. Flue Gas Temperature

SMBSC's Boiler 1 flue gas temperature is approximately 370°F under current operating conditions. For the SCR to effectively control NO_x emissions, flue gas reheat would need to be included with this control measure for it to be technically feasible.

5.1.4 Selective Non-Catalytic Reduction (SNCR)

In the SNCR process, urea or ammonia-based chemicals are injected into the flue gas stream to convert NO to molecular nitrogen, N_2, and water. SNCR control efficiency is typically 25 to 50 percent. Without the participation of a catalyst, the reaction requires a high temperature range to obtain activation energy. The relevant reactions are as follows:

$$2NO + 2NH_3 + 1/2\ O_2 \rightarrow 2\ N_2 + 3H_2O \quad (1)$$

$$4NH_3 + 5O_2 \rightarrow 4NO + 6H_2O \quad (2)$$

At temperature ranges of 1,470°F to 1,830°F, reaction (1) dominates and NO_x emissions are controlled. At temperatures above 2,000°F, reaction (2) will dominate and the ammonia will decompose and increase NO_x emissions. Therefore, it is critical to inject the ammonia or urea reagent into a furnace or boiler at the 1,470°F to 1,830°F temperature range to ensure that NO_x emissions will be controlled.

5.2 Factor 1 – Cost of Compliance

SMBSC has completed a high-level screening-level cost estimate for the selected NO_x emission control measures. Due to the very limited space around existing equipment, a 50 percent markup of the total capital investment (i.e., a 1.5 retrofit factor) was included in the costs. Retrofit installations have increased handling and erection difficulty for many reasons. Access for transportation, laydown space, etc. for new equipment is significantly impeded or restricted. This is because the spaces surrounding the boiler are congested, or the areas surrounding the building support frequent vehicle traffic. The use of a retrofit factor has been justified by previous projects with the MPCA and other states.[8] Finally, the EPA Air Pollution Control Cost Manual notes that retrofit installations are subjective because the plant designers may not have had the foresight to include additional floor space and room between components for new equipment.[9] Retrofits can impose additional costs to "shoehorn" equipment in existing plant space, which is true for SMBSC. Importantly, this initial set of cost estimates do not include additional outage time that may be necessary. Cost summary spreadsheets for the NO_x emission control measures are provided in Appendix A.

The cost effectiveness analysis compares the annualized cost of the technology 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.

The resulting cost effectiveness calculations are summarized in Table 5-2.

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[8] Barr Engineering Co. United Taconite Analysis of Best Available Retrofit Technology. 2006 and U. S. Environmental Protection Agency. Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze (final rule, to be codified at 40 CFR Part 52). Federal Register. January 30, 2014. Vol. 79, 20, p. 5154. EPA–R08–OAR–2012–0026.

[9] U.S. Environmental Protection Agency. EPA Air Pollution Control Cost Manual, Sixth Edition, Section 1, Chapter 2.6.4.2 Retrofit Cost Considerations. 2017. https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

Table 5-2: NO_x Control Cost Summary

Additional Emissions Control Measure	Installed Capital Cost with Retrofit Factor ($)	Indirect Costs ($/yr)	Direct Operating Costs ($/yr)	Total Annualized Costs ($/yr)	Annual Emissions Reduction (tpy)	Pollution Control Cost Effectiveness ($/ton)
Low NO_x Burners	$3,090,000	$442,000	$100,000	$542,000	106	$5,100
Low NO_x Burners with Overfire Air	$5,340,000	$721,000	$100,000	$821,000	231	$3,600
Selective Catalytic Reduction	$39,000,000	$3,400,000	$2,280,000	$5,690,000	813	$7,000
Selective Non-Catalytic Reduction	$6,910,000	$581,000	$699,000	$1,280,000	340	$3,800

The cost effectiveness values for all the potential NO_x emission control measures are greater than the cost effectiveness threshold of $3,100 derived in Section 4.2. Therefore, none of the potential NO_X emission control measures are reasonable for installing on SMBSC's Boiler 1.

Section 5.3 through 5.5 provide a screening-level summary of the remaining three factors evaluated for the NO_x emission control measures, understanding that these projects represent substantial capital investments that are not justified on a cost per ton or absolute cost basis, and therefore further supports the determination that none of the potential NO_X emission control measures are reasonable for installing on SMBSC's Boiler 1.

5.3 Factor 2 – Time Necessary for Compliance

Factor #2 estimates the amount of time needed for full implementation of the different control measures. Typically, time for compliance includes the time needed to develop and approve the new emissions limit into the SIP by state and federal action, then to implement the project necessary to meet the SIP limit via installation and tie-in of equipment for the emissions control measure.

Each NO_x control option would require significant resources and time of at least two to three years to engineer, permit, and install the equipment. Assuming that a SIP limit to approve a new emissions limit would occur in 2022, approximately one year after the MPCA submits its regional haze SIP for the second implementation period, the earliest that the project could be completed is during the 2023 and 2024 inter-campaign periods.

5.4 Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance

The energy and non-air environmental impacts associated with implementation of the above identified NO_x control measures are summarized herein.

As described in section 5.1.1, there are no additional electricity or waste costs associated with low NO_x burners or low NO_x burners with overfire air. However, low NO_x burners have a reduced thermal efficiency.

The addition of an SCR system to SMBSC's Boiler 1 will increase electricity and natural gas consumption. As described in section 5.1.3, the SCR system would require reheat. This would require an additional 5.8 million KW-hr of electricity and 195,000 scf natural gas each year. The SCR system would also require 2 million KW-hr of additional electricity consumption each year.

A SNCR system increases electricity, fuel, and water consumption along with generating additional waste. Water is injected with the reagent, increasing water consumption by 1.4 million gallons per year. An additional 12,000 MMBTU of fuel per year is required to evaporate the injected water and 38 tons of additional ash would be produced due to the increased fuel consumption.

5.5 Factor 4 – Remaining Useful Life of the Source

Because SMBSC is assumed to continue operations for the foreseeable future, the useful life of the individual control measures is used to calculate emission reductions, amortized costs, and cost effectiveness on a dollar per ton basis.

6 SO_2 Four-factor Analysis

This section identifies and describes various SO_2 emission reduction technologies, evaluates the four statutory factors for Boiler 1. Consistent with EPA's guidance and MPCA direction, SMBSC has completed a four-factor analysis for SO_2 as summarized in Sections 6.1 to 6.5.

6.1 SO_2 Control Measures Overview

Sulfur emissions from coal combustion consist primarily of SO_2, with a much lower quantity of SO_3 and gaseous sulfates. These compounds form in the coal as organic and pyritic sulfur. Either form is oxidized during the combustion process. For permitting and design purposes, it is assumed that 100% of the fuel sulfur will convert to SO_2 during the combustion process and that 1% of the uncontrolled SO_2 will oxidize to SO_3. Technically feasible SO_2 control options for SMBSC's Boiler 1 are summarized in Table 6-1.

Table 6-1: Additional SO_2 Control Measures with Potential Application at Coal-Fired Boilers

Control Measure
Spray Dry Absorber
Dry Sorbent Injection

6.1.1 Spray Dry Absorber with Baghouse

The spray dry absorber (SDA) uses slaked lime ($Ca(OH)_2$) as an absorbent to control SO_2 emissions. The lime neutralizes the absorbed SO_2 to form a solid powder.

A SDA requires the installation of a baghouse and lime slaking system. The baghouse is necessary to collect particulate emissions from the spray dry absorber. The lime slaker mixes the dried lime with water in preparation for the lime to be added to the spray dry absorber.

6.1.2 Dry Sorbent Injection

Dry sorbent injection uses a calcium or sodium based reagent. For SMBSC's Boiler 1, trona (sodium sesquicarbonate), a sodium reagent is the selected reagent. In this application, the trona is injected into the flue gas stream to react with SO_2.

The dry sorbent injection system requires the installation of a baghouse to accommodate the additional particulate matter from the injected sorbent and reaction byproducts.

6.2 Factor 1 – Cost of Compliance

SMBSC has completed a high-level screening-level cost estimate for the selected SO_2 emission control measures. Due to the very limited space around existing equipment, a 50 percent markup of the total capital investment (i.e., a 1.5 retrofit factor) was included in the costs. Retrofit installations have increased handling and erection difficulty for many reasons. Access for transportation, laydown space, etc. for new equipment is significantly impeded or restricted. This is because the spaces surrounding the boiler are congested, or the areas surrounding the building support frequent vehicle traffic. The use of a retrofit factor has been justified by previous projects with the MPCA and other states.[10] Finally, the EPA Air Pollution Control Cost Manual notes that retrofit installations are subjective because the plant designers may not have had the foresight to include additional floor space and room between components for new equipment.[11] Retrofits can impose additional costs to "shoehorn" equipment in existing plant space, which is true for SMBSC. Importantly, this initial set of cost estimates do not include additional outage time that may be necessary. Cost summary spreadsheets for the SO_2 emission control measures are provided in Appendix A.

The resulting cost effectiveness calculations are summarized in Table 6-2.

Table 6-2: SO_2 Control Cost Summary, per Unit Basis

Additional Emissions Control Measure	Installed Capital Cost with Retrofit Factor ($)	Indirect Costs ($/yr)	Direct Operating Costs ($/yr)	Total Annualized Costs ($/yr)	Annual Emissions Reduction (tpy)	Pollution Control Cost Effectiveness ($/ton)
Spray Dry Absorber	$82,900,000	$10,600,000	$1,090,000	$11,700,000	707	$16,600
Dry Sorbent Injection	$36,000,000	$4,820,000	$2,170,000	$6,990,000	550	$12,700

The cost effectiveness values for all the SO_2 emission control measures are substantially greater than the cost effectiveness threshold of $5,600 derived in Section 4.2. Therefore, none of the potential SO_2 emission control measures are reasonable for installing on SMBSC's Boiler 1.

Sections 6.3 through 6.5 provide a screening-level summary of the remaining three factors evaluated for the SO_2 control measures, understanding that these projects represent substantial capital investments that are not justified on a cost per ton or absolute cost basis, and therefore further supports the determination that none of the potential SO_2 emission control measures are reasonable for installing on SMBSC's Boiler 1.

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[10] Barr Engineering Co. United Taconite Analysis of Best Available Retrofit Technology. 2006 and U. S. Environmental Protection Agency. Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze (final rule, to be codified at 40 CFR Part 52). Federal Register. January 30, 2014. Vol. 79, 20, p. 5154. EPA–R08–OAR–2012–0026.

[11] U.S. Environmental Protection Agency. EPA Air Pollution Control Cost Manual, Sixth Edition, Section 1, Chapter 2.6.4.2 Retrofit Cost Considerations. 2017. https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

6.3 Factor 2 – Time Necessary for Compliance

Factor #2 estimates the amount of time needed for full implementation of the different control measures. Typically, time for compliance includes the time needed to develop and approve the new emissions limit into the SIP by state and federal action, then to implement the project necessary to meet the SIP limit via installation and tie-in of equipment for the emissions control measure.

Either project control option would require significant resources and time of at least two to three years to engineer, permit, and install the equipment. Assuming that a SIP limit to approve a new emissions limit would occur in 2022, approximately one year after the MPCA submits its regional haze SIP for the second implementation period, the earliest that the project could be completed is during the 2023 and 2024 inter-campaign periods.

6.4 Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance

The energy and non-air environmental impacts associated with implementation of the above identified SO_2 control measures are summarized herein.

The SDA and DSI systems both result in an increase in electricity consumption as well as an increase in solid waste generation. Electricity is required to operate the additional system components for each control measure Additional waste streams will be generated from the spent sorbent and unreacted sorbent waste generation. Table 6-3 lists estimated quantities of each material below:

Table 6-3: SO_2 Control Measure Environmental Impacts

Parameter	SDA	DSI
Additional Electricity Consumption	2.9 million KW-hr per year	1.7 million KW-hr per year
Spent and Unreacted Sorbent Waste Generation	1,600 tons per year	3,500 tons per year

6.5 Factor 4 – Remaining Useful Life of the Source

Because SMBSC is assumed to continue operations for the foreseeable future, the useful life of the individual control measures is used to calculate emission reductions, amortized costs, and cost effectiveness on a dollar per ton basis.

7 Visibility Impacts Review

The Regional Haze Rule (RHR) requires that the SIP include an analysis of "baseline, current, and natural visibility conditions; progress to date; and the uniform rate of progress."[12] This is used to establish progress goals to be achieved by the end of the implementation period in 2028.[13] Section 7.1 provides an analysis of current visibility conditions at the three Class I areas being evaluated by MPCA: Boundary Waters, Voyageurs, and Isle Royale. Since 2009, the regional haze impairment at all three Class I areas has been declining (i.e., visibility has been improving). Additionally, regional haze impairment fell below the expected 2028 Universal Rate of Progress (URP) goal in 2016 for Boundary Waters and Isle Royale, and 2018 for Voyageurs. Because the existing visibility data demonstrates sustained progress towards visibility goals and the 5-year average visibility impairment on the most impaired days is already below the URP, the MPCA should use the current trend of emission reductions to demonstrate reasonable progress.

Additionally, the 2019 SIP Guidance provides criteria to evaluate when selecting sources that must complete an analysis of emission controls. One of the options for estimating baseline visibility impacts is a particle trajectory analysis.[14] In addition, the 2019 SIP Guidance says that a state can consider visibility impacts in Class I areas when evaluating possible emission control measures.[15] Section 7.2.2 provides results from two different particle trajectory analyses for the most impaired days at the Voyageurs and Boundary Waters visibility monitors. The results of the analysis conclude that SMBSC provides virtually no contribution to visibility impairment at the nearby Class I areas. Thus, additional control measures implemented at SMBSC are unlikely to provide a substantial improvement in visibility in the Class I areas.

7.1 Emission Inventory and Photochemical Modeling Inputs Review

As described in Section 3-2, to understand the emissions from Boiler 1 used in the regional haze modeling analysis completed by US EPA, Barr acquired the 2016 and 2028 non-electric generating unit (nonEGU) inventory from the US EPA and was advised by MPCA that no changes have been made to those inventories for SMBSC.

Table 7-1 includes the SO_2 and NO_x inventory summary information for Boiler 1.

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[12] 40 CFR 51.308(f)(1)

[13] 40 CFR 51.308(f)(3)

[14] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003. Page 13.

[15] Ibid, Page 34.

Table 7-1 2016 and 2028 EPA Modeling Emissions Inventory for SMBSC Sources (TPY)

Units	2016 SO_2	2028 SO_2	2016 NO_x	2028 NO_x
Boiler 1	806	786	930	907

As expected, the 2016 modeled emissions match the CEMs data reported to MPCA. Boiler 1 has a projection factor from 2016 to 2028 of 0.9756 for coal-fired, non-utility boilers in Minnesota (i.e., not just SMBSC Boiler 1). This represents a 2.5% decrease in emissions from 2016 when projecting forward to 2028 (roughly 0.2% per year). Source classification codes (SCC) beginning with "102002" were projected using this factor. Specifically, this projection factor was used for SMBSC and the other beet sugar processing plant boilers as well. The analysis conducted for the four-factor analysis includes the 2028 emissions.

7.2 Visibility Impacts Review

7.2.1 IMPROVE Monitoring Data Analysis

MPCA tracks progress towards the natural visibility conditions using data from the IMPROVE visibility monitors at Boundary Waters (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1).[16] The visibility metric is based on the 20% most anthropogenically impaired days and the 20% clearest days, with visibility being measured in deciviews (dv). The EPA issued guidance for tracking visibility progress, including the methods for selecting the "most impaired days," on December 20, 2018.[17] Originally, the RHR considered the "haziest days" but USEPA recognized that naturally occurring events (e.g., wildfires and dust storms) could be contributing to visibility and that the "visibility improvements resulting from decreases in anthropogenic emissions can be hidden in this uncontrollable natural variability."[18]

Figure 7-1 through Figure 7-3 show the rolling 5-year average visibility impairment compared with the URP glidepath[19] at Boundary Waters (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1), respectively. Regional haze impairment has been declining since 2009 for all three Class I areas that are tracked by MPCA. Impacts to the most impaired days at Boundary Waters and Isle Royale fell below the expected 2028 URP goal in 2016 and have continued trending downward since. Voyageurs' impaired days fell below the 2028 URP in 2018 and is also on a downward trend.

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[16] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

[17] https://www.epa.gov/visibility/technical-guidance-tracking-visibility-progress-second-implementation-period-regional

[18] USEPA, Federal Register, 05/04/2016, Page 26948

[19] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

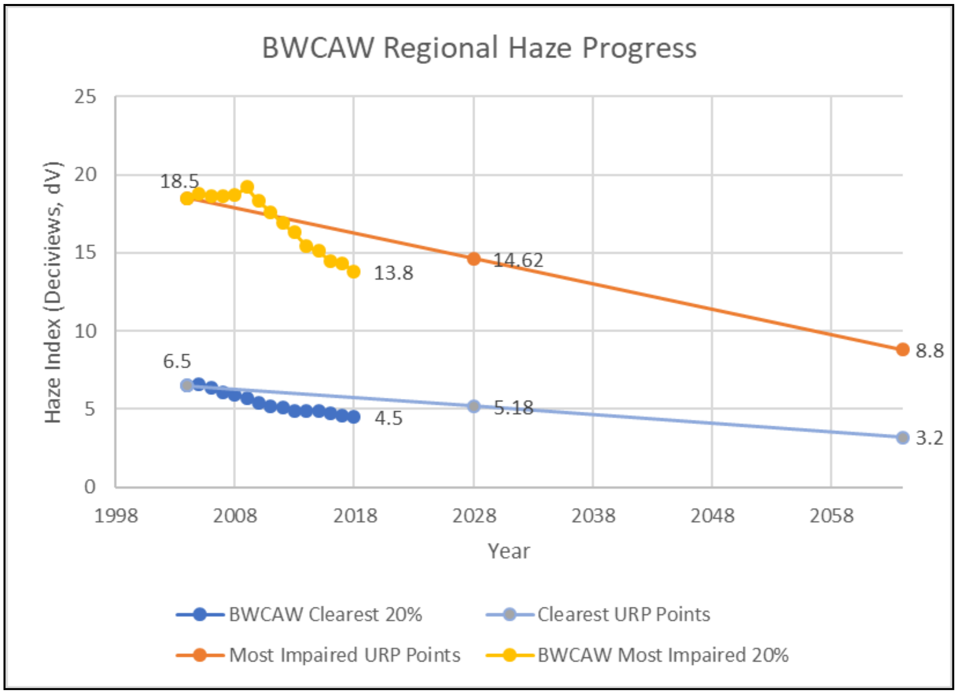

Figure 7-1: Visibility Trend versus URP – Boundary Waters Canoe Area (BOWA1)

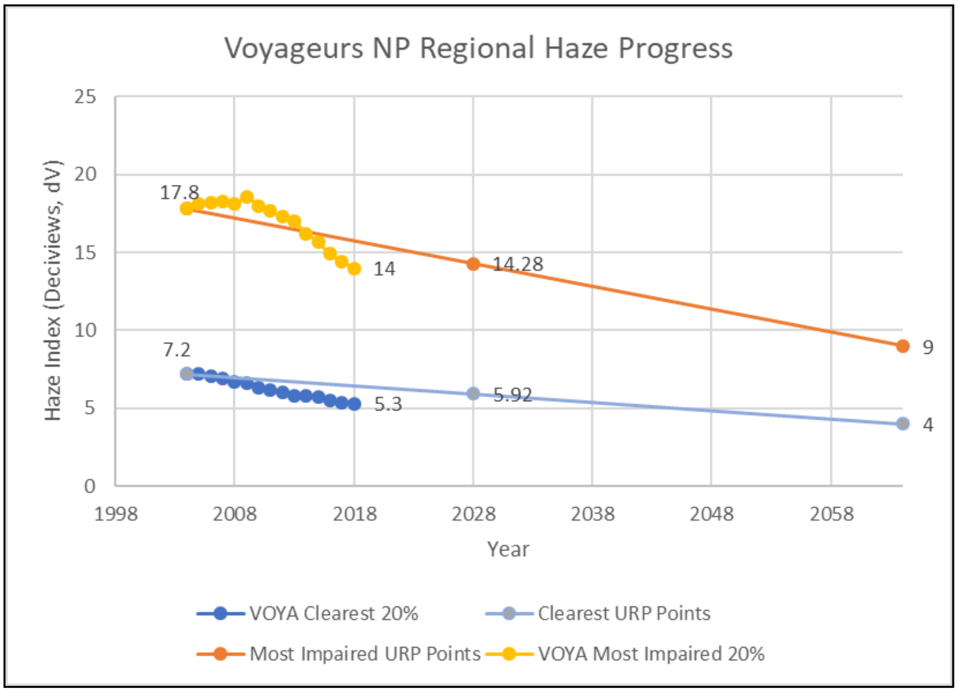

Figure 7-2: Visibility Trend versus URP – Voyageurs National Park (VOYA1)

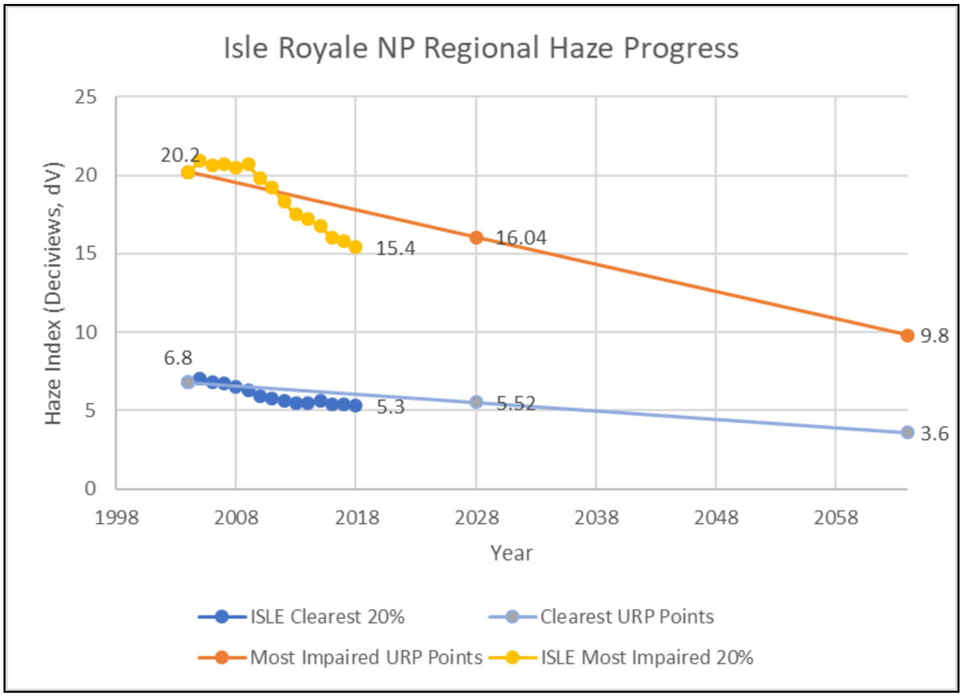

Figure 7-3: Visibility Trend versus URP – Isle Royale National Park (ISLE1)

The downward visibility trend for each of the Class I monitors described above can be mostly attributed to the reductions in ammonium sulfate and, to a lesser extent, ammonium nitrate as shown in Figure 7-4. These reductions are a result of a number of different actions taken to reduce emissions from several sources, including:

- Installation of BART during the first RHR implementation period
- Emission reductions from a variety of industries, including pulp and paper mill sources, due to updated rules and regulations
- Transition of power generation systems from coal to natural gas and renewables (wind and solar)

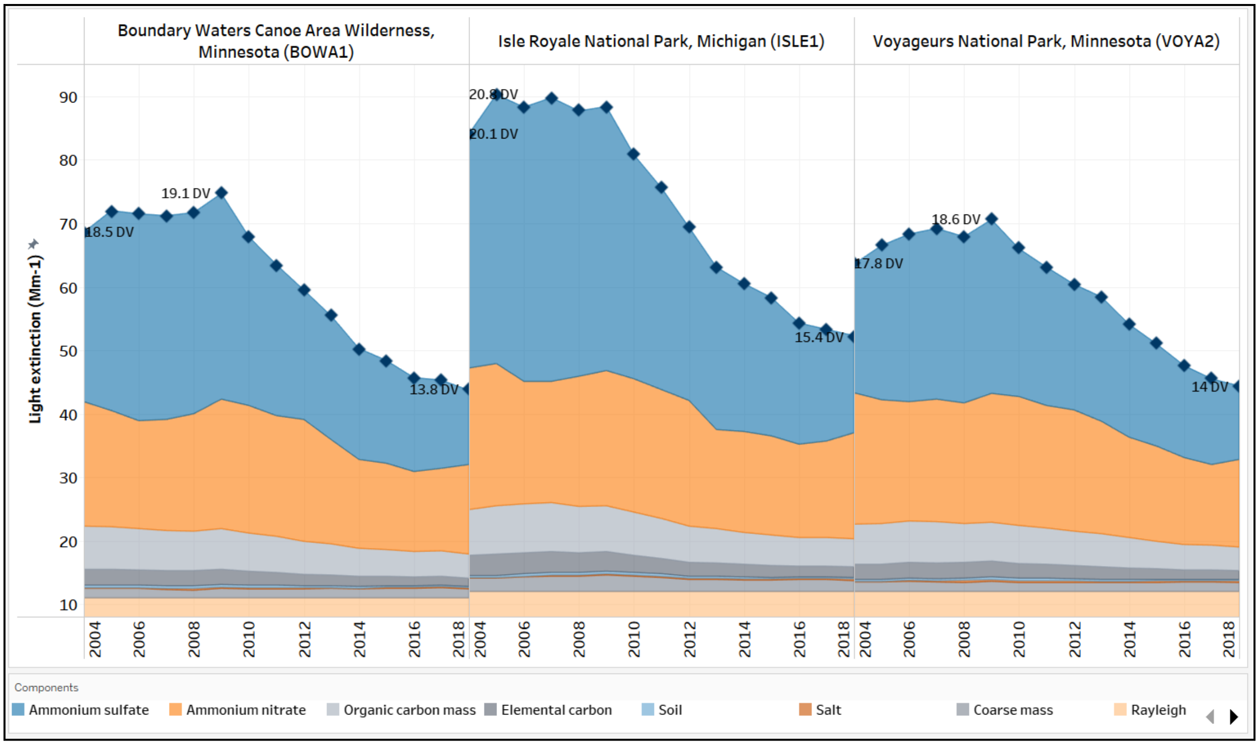

Figure 7-4: Visibility Components Trend for each Class 1 Monitor from 2004-2018[20]

Additionally, since the end of 2018, many facilities have implemented emission reduction actions that are not represented in the data in Figure 7-1 through Figure 7-4 including:

- Retiring two coal-fired boilers at the Minnesota Power Boswell Energy Center in Cohasset at the end of 2018
- The compliance schedules for the NO_x emission reductions required by the Taconite Federal Implementation Plan (FIP) Establishing BART for Taconite Plants (40 CFR 52.1235)
- Other planned emission reduction projects that are scheduled to occur in Minnesota prior to 2028, such as the Xcel Energy boiler retirements as detailed in their Upper Midwest Integrated Resource Plan, 2020-2034

These emission reductions will further improve the visibility in the Class I areas, thus helping to ensure the trend remains below the URP to reach the 2028 visibility goal.

The 2019 Guidance says that the state will determine which emission control measures are necessary to make reasonable progress in the affected Class I areas.[21] Because the IMPROVE monitoring network data demonstrates sustained progress towards visibility goals and the 5-year average visibility impairment on

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[20] MPCA – Regional Haze Tableau Public. https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

[21] Ibid, Page 9.

the most impaired days is already below the URP, the MPCA should use the current trend of emission reductions to demonstrate reasonable progress.

7.2.2 Transport Frequency and Trajectory Analysis

The 2019 Guidance says that a state should estimate baseline visibility impacts in Class I areas when selecting which sources must conduct a four-factor analysis.[22] In addition, the 2019 Guidance says that a state can consider visibility impacts in Class I areas when evaluating possible emission control measures.[23]

As part of this evaluation, Barr considered the distance from SMBSC to the nearest Class I areas. The distance is 400-450 km to both Boundary Waters and Voyageurs and over 550 km to Isle Royale. The distances alone are enough to eliminate SMBSC for consideration as part of any contribution analysis at the Class I areas. As part of Class I area PSD permitting exercises, Federal Land Managers rarely evaluate permits at distances over 300 km and then only when sources are considerably larger than Boiler 1. The rationale for exclusion of sources at these great distances is logical as the pollution has a long time to disperse, react, and/or deposit thereby reducing the downwind impact on the Class I areas.

Further, using the 2028 emissions, the emissions in tons per year divided by the distance in kilometers (Q/d) is less than 4. Traditionally, a Q/d of 10 has been used to screen out sources from inclusion of visibility analysis on Class I areas.

Even if the distance and emissions are not used to screen out the boiler from this evaluation, Barr completed a wind rose for Olivia, MN Regional airport using 2006 -2020 data (Figure 7-5). This rose illustrates the predominant wind directions in this part of Minnesota are from the northwest and southeast/south-southeast. The frequency from the southwest that would be necessary to transport SMBSC emissions to any of the Class I areas is very small (less than 1% of the time). Again, this lack of frequency is sufficient to conclude that the impact of Boiler 1 would not contribute to visibility impairment at the upper Midwest Class I areas.

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[22] Ibid, Page 12.

[23] Ibid, Page 34.

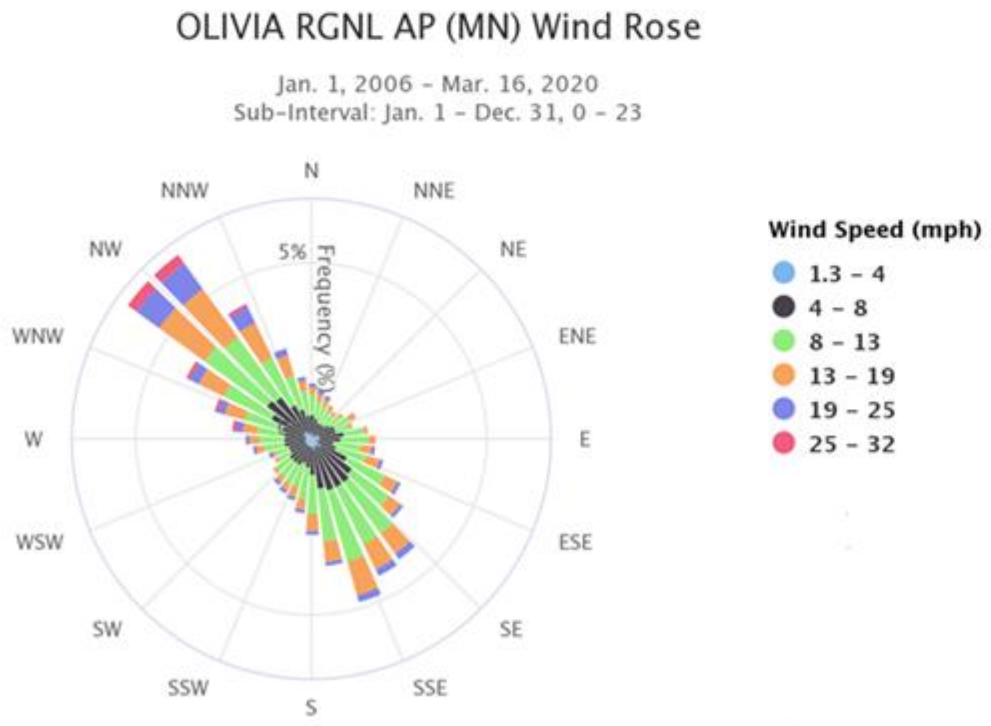

Figure 7-5: Olivia Wind Rose

Barr reviewed the trajectory analyses completed by MPCA from 2014-2016 with a focus on Voyageurs, highlighted in Figure 7-6. The trajectory analyses for the most impaired days indicates very few days (<5%) with trajectories passing over SMBSC. Alternatively, many more days showed impacts from the Minneapolis / St. Paul and other areas. In addition, Barr conducted a forward-trajectory analysis from SMBSC's location to the Class I areas on days that exhibit 20% most impaired conditions for 2017 and 2018 (Figures 7-7 and 7-8, respectively). This analysis also indicates that there are only two days per year[24] with potential impact on the upper Midwest Class I areas. It is also important to remember the distance between the source and the Class I areas.

Furthermore, SMBSC Boiler 1 emissions represent less than 0.6% of statewide anthropogenic NO_X + SO_2 emissions (1,735 tons SMBSC / 281,221 tons 2017 statewide[25]). For such long trajectories covering nearly the length of the state, it is unlikely the SMBSC emissions would make up a significant portion of impacts even for trajectories passing over the facility.

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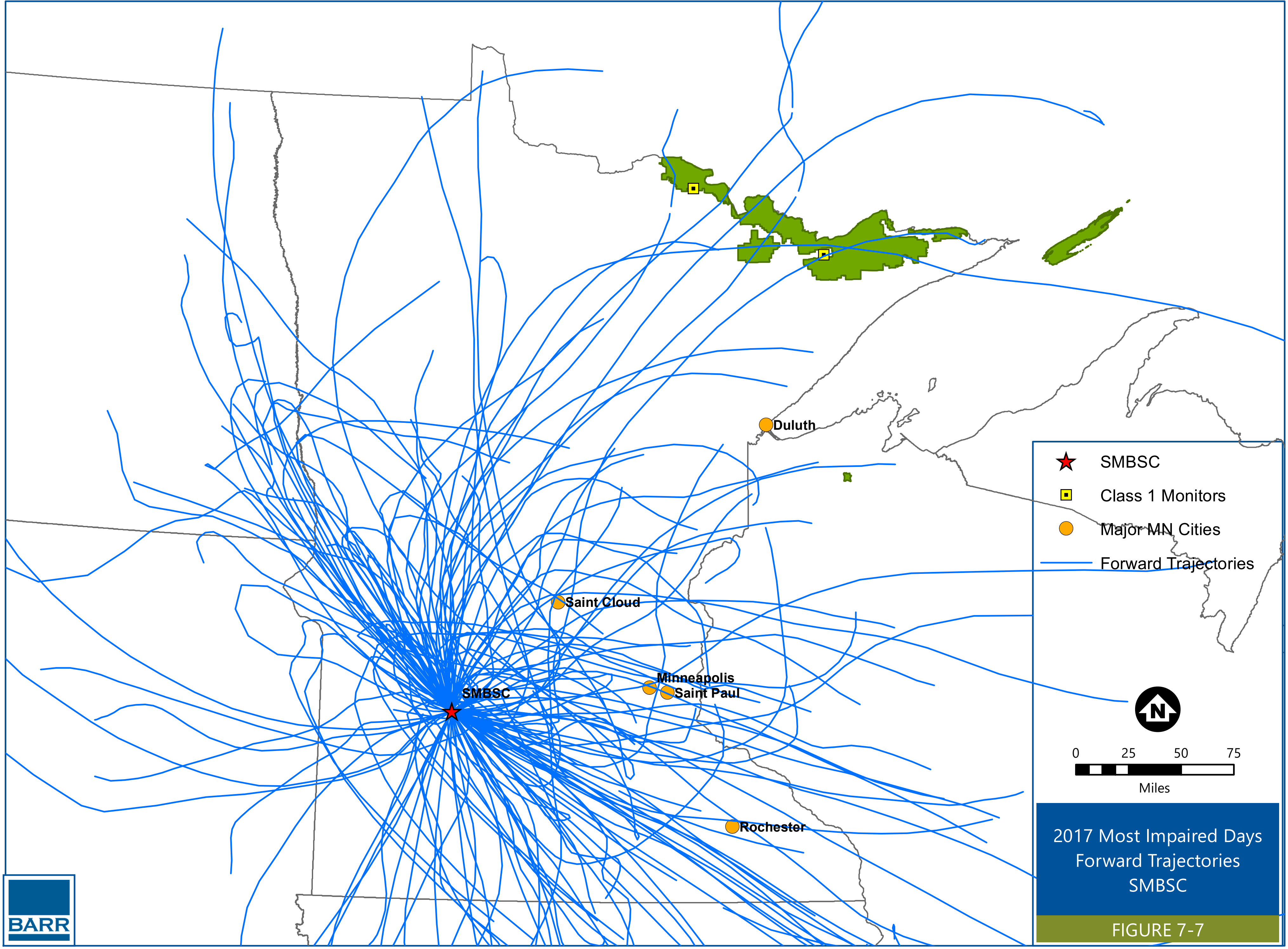
[24] Forward trajectories were modeled using staggered start times throughout the days of monitored impairment. Trajectories crossing the Class I areas in 2017 are attributable to two modeled days of multiple trajectories, rather than several days of impairment.

[25] MPCA 2017 statewide air emissions inventory. https://www.pca.state.mn.us/air/statewide-and-county-air-emissions

Figure 7-6: Voyageurs Trajectories for Most Impaired Days 2014-2016

7.3 Visibility Review Summary

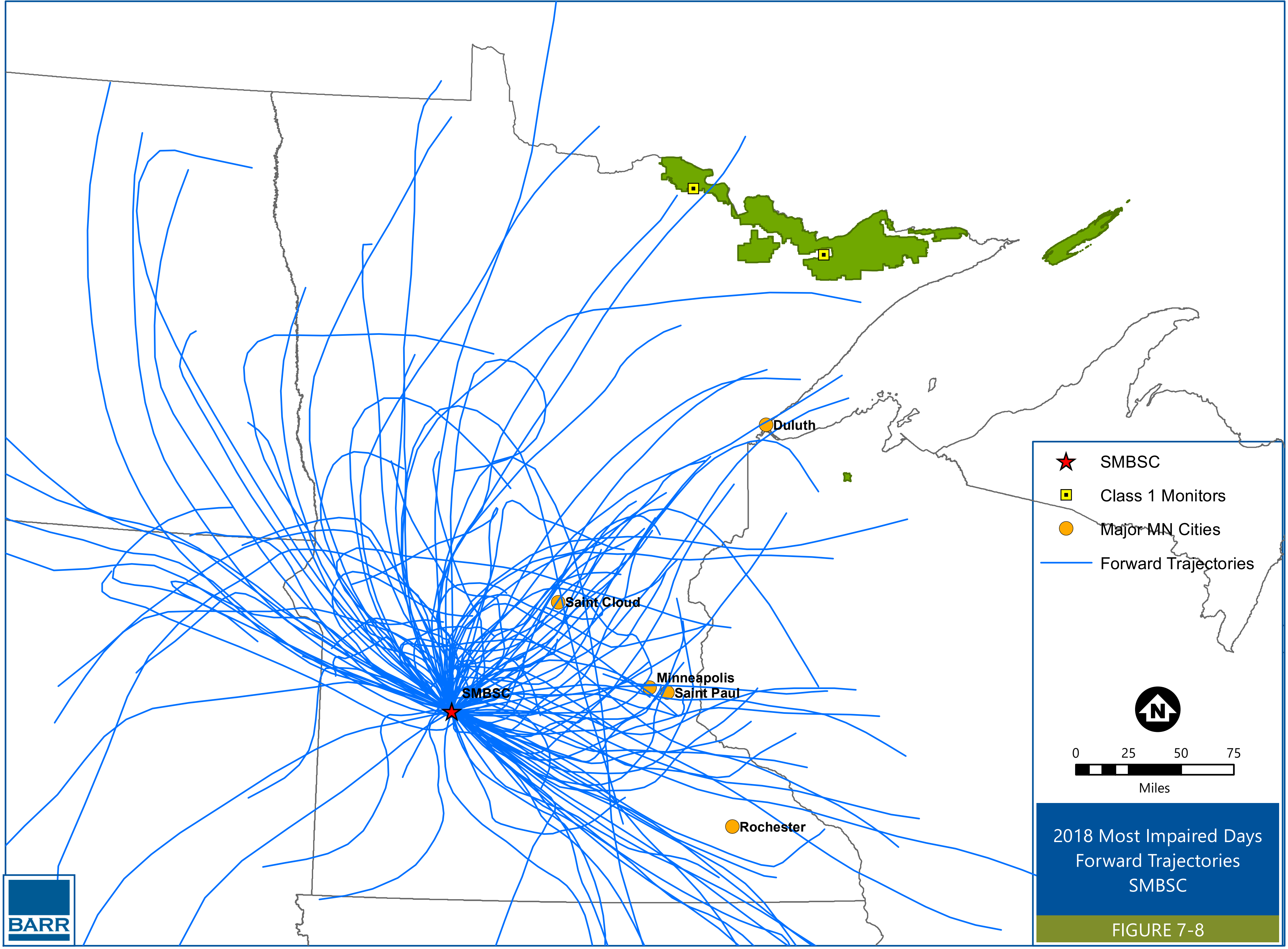
The level of emissions along with the distance to the upper Midwest Class I areas indicate that SMBSC is unlikely to be a significant contributor to visibility impairment. Review of wind direction trends and trajectories associated with impacted days further reinforces the minimal potential for contribution by SMBSC. The results of the analysis conclude that SMBSC provides virtually no contribution to visibility impairment at the nearby Class I areas. Thus, additional control measures implemented at SMBSC are unlikely to provide a substantial improvement in visibility in the Class I areas.



2017 Most Impaired Days Forward Trajectories SMBSC

FIGURE 7-7

BARR



2018 Most Impaired Days
Forward Trajectories
SMBSC

FIGURE 7-8

Appendix A

Control Cost Analysis for NO_X and SO_2

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 1: Cost Summary

NO_x Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $[2]	Annualized Operating Cost $/yr[2]	Pollution Control Cost $/ton[2]
Selective Catalytic Reduction with Reheat (SCR)	90%	94.5	812.5	$38,983,220	$5,686,381	$6,999
Low NOx Burners (LNB) Coal-Fired[1]	12%	801.0	105.9	$2,057,668	$542,043	$5,117
Low NOx Burners + Over Fire Air (LNB+OFA) Coal-Fired[1]	25%	676.4	230.5	$3,560,926	$820,926	$3,561
Selective Non-Catalytic Reduction (SNCR)	38%	566.8	340.1	$6,908,987	$1,280,578	$3,765

1) Control efficiency based on vendor estimated performance compared to baseline emission rates

2) Equipment costs scaled to 2019 dollars using the most current Chemical Engineering Plant Cost Index (CEPCI). All other costs scaled to 2020 dollars

SO_2 Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton
Spray Dry Absorber (SDA) with Baghouse (including lime slaking system)	90%	78.6	707.2	$56,147,603	$11,708,110	$16,556
Dry Sorbent Injection (DSI) with Baghouse (including trona injection system)	70%	235.7	550.0	$36,015,563	$6,985,015	$12,700

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 2: Summary of Utility, Chemical and Supply Costs

Operating Unit:	Boiler 1
Emission Unit Number	EQUI17
Stack/Vent Number	STRU25

Study Year 2020

Item	2020 Unit Cost	Units	Cost	Year	Data Source	Notes
Operating Labor	68	$/hr	60	2016	EPA SCR Control Cost Manual Spreadsheet	
Maintenance Labor	68	$/hr				Assumed to be equivalent to operating labor
Installation Labor	68	$/hr				Assumed to be equivalent to operating labor
Electricity	0.08	$/kwh			2015-2019 EIA Average prices for the commerical sector	
Natural Gas	3.90	$/kscf			2015-2019 EIA Average prices for the commerical sector	
Water	5.13	$/mgal	4.17	2013	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Compressed Air	0.48	$/kscf	0.38	2012	Taconite FIP Docket	
Chemicals & Supplies						
Lime	183.68	$/ton	145.00	2012	Taconite FIP Docket	
Trona	285.00	$/ton		2020	Reagent cost for trona from another Barr Engineering Co. Project.	
Urea 50% Solution	1.81	$/gallon	1.66	2017	EPA SCR Control Cost Manual Spreadsheet	
Fuel Cost	2.13		1.89	2016	EPA SNCR Control Cost Manual Spreadsheet	
Estimated operating life of the catalyst ($H_{catalyst}$)	20,000	hours			EPA Control Cost Manual for SCR suggests 16,000 - 24,000 hours	
SCR Catalyst cost ($CC_{replace}$)	255	$/cubic foot	227	2016	EPA SCR Control Cost Manual Spreadsheet	Cost includes removal and disposal/regeneration of existing catalyst and installation of new catalyst
Fabric Filter Bags	228.02	$/bag	180	2012	Taconite FIP Docket	
Other						
Sales Tax	6.875%			2020	Minnesota sales tax rate	
Interest Rate	5.50%			2016	EPA SCR Control Cost Manual Spreadsheet	
Solid Waste Disposal	63.34	$/ton	50	2012	Taconite FIP Docket	
Contingencies	10%	of purchased equip cost (B)			EPA Cost Control Cost Manual Chapter 2	Suggested contingency range of 5% to 15% of total capital investment
Markup on capital investment (retrofit factor)	50%				EPA Cost Control Cost Manual Chapter 2	
Operating Information						
Annual Op. Hrs	7,536	Hours			Average of 2015-2019 Operating Data	
Utilization Rate	100%				Assumed	
Design Capacity	472.4	MMBTU/hr			Boiler Design Capacity	
Equipment Life	20	yrs			Assumed	
Temperature	370	Deg F			SMBSC CEMS Stack Temperature Data	2018-2020 Average, excluding periods of boiler shutdown/startup
Moisture Content	11.8%				2014 Boiler 1 Hg Stack Test Data	
Actual Flow Rate	209,000	acfm			2014 Boiler 1 Hg Stack Test Data	
Standardized Flow Rate	132,954	scfm @ 68º F	123,889	scfm @ 32º F	Calculated Value	
Dry Std Flow Rate	117,332	dscfm @ 68º F			Calculated Value	
Fuel higher heating value (HHV)	9,152	BTU/lb			SMBSC Site Specific Data	Average of 2015-2019 Operating Data
Plant Elevation	1,100	Feet above sea level				Renville, MN elevation
Sulfur Content (%)	0.28	%			SMBSC Site Specific Data	Average of 2015-2019 Operating Data
# days boiler operates	314	days			SMBSC Site Specific Data	Average of 2015-2019 Operating Data
	Baseline Emissions		**lb/hr**	**ton/year**		
Pollutant	**Lb/Hr**	**Ton/Year**	**ppmv**	**ppmv**	**lb/mmbtu**	
Nitrous Oxides (NOx)	240.7	906.9	286	286.1	0.48	Baseline ton/year is based on 2028 NOx modeling emission inventory. Lb/MMBtu is based on 2015-2019 CEMS average
Sulfur Dioxides (SO2)	208.5	785.8	178	178.0		Baseline ton/year is based on 2028 SO2 modeling emission inventory.
SDA - SO_2 Control Efficiency	90%				EPA fact sheet for flue gas desulfurization (new installations) https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf	
DSI - SO_2 Control Efficiency	70%	Trona Ore Control Efficiency			Control efficiency is based on trona as injected reagent.	
SCR - NO_x Control Efficiency	90%				Common design basis for SCR units per EPA Control Cost Manual	
LNB - NO_x Performance	0.45	lb/MMBtu			Vendor estimated burner performance	
LNB+OFA- NO_x Performance	0.38	lb/MMBtu			Vendor estimated burner performance	
SNCR - NO_x Performance	0.30	lb/MMBtu			EPA Control Cost Manual SCR spreadshet default outlet NOx emission rate	

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 3: NO_x Control - Selective Catalytic Reduction with Reheat

Operating Unit: **Boiler 1**

Emission Unit Number	EQUI17		Stack/Vent Number	STRU25	
Design Capacity	472	mmbtu/hr	Standardized Flow Rate	123,889	scfm @ 32º F
Expected Utilization Rate	100%		Temperature	370	Deg F
Expected Annual Hours of Operation	7,536	Hours	Moisture Content	11.8%	
Annual Interest Rate	5.5%		Actual Flow Rate	209,000	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	132,954	scfm @ 68º F
			Dry Std Flow Rate	117,332	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Total Capital Investment (TCI)							SCR Only	37,031,999
							SCR + Reheat	**38,983,220**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.					SCR + Reheat	**2,280,595**
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost					SCR + Reheat	**3,398,577**
Total Annual Cost (Annualized Capital Cost + Operating Cost							SCR + Reheat	**5,686,381**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrous Oxides (NOx)	240.7	906.9	90%	94.5	812.5	6,999

Notes & Assumptions

1 Estimated Equipment Cost per EPA Air Pollution Control Cost Manual 7th Ed SCR Control Cost Spreadsheet
2 Costs scaled to current dollars from the Chemical Engineering Plant Cost Index (CEPCI)

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 3: NOx Control - Selective Catalytic Reduction with Reheat

CAPITAL COSTS			
SCR Capital Costs (SCRcost)		*Refer to the SCR Summary tab*	20,134,912
Reagent Preparation Costs (RPC)		*Refer to the SCR Summary tab*	3,581,809
Air Pre-Heater Costs (APHC)		*Refer to the SCR Summary tab*	-
Balance of Plant Costs (BPC)		*Refer to the SCR Summary tab*	4,769,432
Retrofit factor	50%	*of TCI, see SCR Summary tab*	
Total Capital Investment (TCI)			**37,031,999**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Maintenance			
Annual Maintenance Cost =		*Refer to the SCR Summary tab*	185,160
Utilities, Supplies, Replacements & Waste Management			
Annual Electricity Cost =		*Refer to the SCR Summary tab*	162,055
Annual Catalyst Replacement Cost =		*Refer to the SCR Summary tab*	212,743
Annual Reagent Cost =		*Refer to the SCR Summary tab*	400,990
Total Annual Direct Operating Costs			**960,949**
Indirect Operating Costs			
Administrative Charges (AC) =		*Refer to the SCR Summary tab*	4,766
Capital Recovery Costs (CR)=	0.0837	*Refer to the SCR Summary tab*	3,099,578
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**3,104,345**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**4,065,293**

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 3: NOx Control - Selective Catalytic Reduction with Reheat

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catayst - Refer to the SCR Summary Tab

Reagent Use
Refer to the SCR Summary tab

Operating Cost Calculations	**Annual hours of operation:**	**7,536**
Refer to the SCR Summary tab	**Utilization Rate:**	**100%**

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 4: NO_x Control - Flue Gas Reheat for SCR (Thermal Oxidizer)

Operating Unit: **Boiler 1**

Emission Unit Number	EQUI17		Stack/Vent Number	STRU25		**Chemical Engineering**	
Desgin Capacity	472	MMBTU/hr	Standardized Flow Rate	123,889	scfm @ 32º F	**Chemical Plant Cost Index**	
Expected Utilization Rate	100%		Temperature	370	Deg F	1998/1999	390
Expected Annual Hours of Operation	7,536	Hours	Moisture Content	11.8%		2019	607.5
Annual Interest Rate	5.5%		Actual Flow Rate	209,000	acfm	Inflation Adj	1.56
Expected Equipment Life	20	yrs	Standardized Flow Rate	132,954	scfm @ 68º F		
			Dry Std Flow Rate	117,332	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			635,318
Purchased Equipment Total (B)	22%	of control device cost (A)	**774,294**
Installation - Standard Costs	30%	of purchased equip cost (B)	232,288
Installation - Site Specific Costs			NA
Installation Total			232,288
Total Direct Capital Cost, DC			1,006,582
Total Indirect Capital Costs, IC	38%	of purchased equip cost (B)	294,232
Total Capital Investment (TCI) = DC + IC			**1,300,814**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	1,319,647
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	301,441
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,621,087**

Notes & Assumptions

1 Equipment cost estimate EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 3.2 Chapter 2.5.1
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 3.2 Chapter 2

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 4: NOx Control - Flue Gas Reheat for SCR (Thermal Oxidizer)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**635,318**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	63,532
MN Sales Taxes	6.9%	of control device cost (A)	43,678
Freight	5%	of control device cost (A)	31,766
Purchased Equipment Total (B)	22%		**774,294**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	61,944
Handling & erection	14%	of purchased equip cost (B)	108,401
Electrical	4%	of purchased equip cost (B)	30,972
Piping	2%	of purchased equip cost (B)	15,486
Insulation	1%	of purchased equip cost (B)	7,743
Painting	1%	of purchased equip cost (B)	7,743
Installation Subtotal Standard Expenses	30%		**232,288**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			**232,288**
Total Direct Capital Cost, DC			**1,006,582**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	77,429
Construction & field expenses	5%	of purchased equip cost (B)	38,715
Contractor fees	10%	of purchased equip cost (B)	77,429
Start-up	2%	of purchased equip cost (B)	15,486
Performance test	1%	of purchased equip cost (B)	7,743
Model Studies		of purchased equip cost (B)	0
Contingencies	10%	of purchased equip cost (B)	77,429
Total Indirect Capital Costs, IC	38%	of purchased equip cost (B)	**294,232**
Total Capital Investment (TCI) = DC + IC			**1,300,814**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**1,300,814**
Total Capital Investment (TCI) with Retrofit Factor	50%		**1,951,221**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	67.53	$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr	31,807
Supervisor	15%	15% of Operator Costs	4,771
Maintenance			
Maintenance Labor	67.53	$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr	31,807
Maintenance Materials	100%	of maintenance labor costs	31,807
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.08	$/kwh, 774 kW-hr, 7536 hr/yr, 100% utilization	464,503
Natural Gas	3.90	$/mscf, 428 scfm, 7536 hr/yr, 100% utilization	754,952
Total Annual Direct Operating Costs			**1,319,647**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	60,115
Administration (2% total capital costs)	2%	of total capital costs (TCI)	39,024
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	19,512
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	19,512
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	163,277
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**301,441**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,621,087**

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 4: NOx Control - Flue Gas Reheat for SCR (Thermal Oxidizer)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalyst:	**Catalyst**	
Equipment Life	3	years
CRF	0.3707	
Rep part cost per unit	0	$/ft^3
Amount Required	39	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	0	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr	OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use	Flow acfm		Δ P in H2O	Efficiency	Hp	kW	
Blower, Thermal	209,000		19	0.6		774.3	EPA Cost Cont Manual 6th ed - Oxidizders Chapter 2.5.2.1
Blower, Catalytic	209,000		23	0.6		937.4	EPA Cost Cont Manual 6th ed - Oxidizders Chapter 2.5.2.1
Oxidizer Type	**thermal**	(catalytic or thermal)				774.3	

Reagent Use & Other Operating Costs Oxidizers - NA

Operating Cost Calculations			**Annual hours of operation:**			**7,536**	
			Utilization Rate:			**100%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	67.53	$/Hr	0.5	hr/8 hr shift	471	31,807	$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr
Supervisor	15%	of Op.			NA	4,771	15% of Operator Costs
Maintenance							
Maint Labor	67.53	$/Hr	0.5	hr/8 hr shift	471	31,807	$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	31,807	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.080	$/kwh	774.3	kW-hr	5,835,464	464,503	$/kwh, 774 kW-hr, 7536 hr/yr, 100% utilization
Natural Gas	3.90	$/mscf	428	scfm	193,577	754,952	$/mscf, 428 scfm, 7536 hr/yr, 100% utilization

*annual use rate is in same units of measurement as the unit cost factor

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 4: NOx Control - Flue Gas Reheat for SCR (Thermal Oxidizer)

Flue Gas Re-Heat Equipment Cost Estimate Basis Thermal Oxidizer with 70% Heat Recovery

Auxiliary Fuel Use Equation 3.19

T_{wi}	370	Deg F - Temperature of waste gas into heat recovery
T_{fi}	650	Deg F - Temperature of Flue gas into heat recovery
T_{ref}	77	Deg F - Reference temperature for fuel combustion calculations
FER	70%	Factional Heat Recovery % Heat recovery section efficiency
T_{wo}	566	Deg F - Temperature of waste gas out of heat recovery
T_{fo}	454	Deg F - Temperature of flue gas out of heat recovery
$-h_{caf}$	21502	Btu/lb Heat of combustion auxiliary fuel (methane)
$-h_{wg}$	0	Btu/lb Heat of combustion waste gas
$C_{p\ wg}$	0.2684	Btu/lb - Deg F Heat Capacity of waste gas (air)
p_{wg}	0.0739	lb/scf - Density of waste gas (air) at 77 Deg F
p_{af}	0.0408	lb/scf - Density of auxiliary fuel (methane) at 77 Deg F
Q_{wg}	132,954	scfm - Flow of waste gas
Q_{af}	428	scfm - Flow of auxiliary fuel

Year 2005 Inflation Rate 3.0%

Cost Calculations 133,382 scfm Flue Gas Cost in 1989 $'s $407,859

Current Cost Using CHE Plant Cost Index $635,318

Heat Rec %	A	B	
0	10,294	0.2355	Exponents per equation 3.24
0.3	13,149	0.2609	Exponents per equation 3.25
0.5	17,056	0.2502	Exponents per equation 3.26
0.7	21,342	0.2500	Exponents per equation 3.27

Indurator Flue Gas Heat Capacity - Basis Typical Composition

100 scfm 359 scf/lbmole

		Gas Composition		lb/hr f	wt %	Cp Gas	Cp Flue
28	mw CO	0	v %	0			
44	mw CO2	15	v %	184	22.0%	0.24	0.0528
18	mw H2O	10	v %	50	6.0%	0.46	0.0276
28	mw N2	60	v %	468	56.0%	0.27	0.1512
32	mw O2	15	v %	134	16.0%	0.23	0.0368
	Cp Flue Gas	100	v %	836	100.0%		0.2684

Reference: OAQPS Control Cost Manual 5th Ed Feb 1996 - Chapter 3 Thermal & Catalytic Incinerators
(EPA 453/B-96-001)

Air Pollution Control Cost Estimation Spreadsheet
For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO_x emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO_x within a specific temperature range to produce N_2 and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 6). For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retrofit of an existing boiler. 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.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?

What type of fuel does the unit burn?

Is the SCR for a new boiler or retrofit of an existing boiler?

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	472	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	9,152	Btu/lb
What is the estimated actual annual fuel consumption?		
Enter the net plant heat input rate (NPHR)	10	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 1,100 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned:

Enter the sulfur content (%S) = 0.28 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

○ Method 1
● Method 2
○ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	314	days
Number of days the boiler operates (t_{plant})	314	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.48	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.05	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	0.525	

*The SRF value of 0.525 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	209,000	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	20,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	516	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	50	percent*
Density of reagent as stored (ρ_{stored})	71	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 50% and density of 71 lbs/cft are default values for urea reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used

Enter the cost data for the proposed SCR:

Desired dollar-year	2020			
CEPCI for 2020	607.5	2019 CEPCI Final Value	541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.50	Percent*		
Reagent ($Cost_{reag}$)	1.814	$/gallon for 50% urea		
Electricity ($Cost_{elect}$)	0.0796	$/kWh		
Catalyst cost ($CC_{replace}$)	255.49	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst		
Operator Labor Rate	67.53	$/hour (including benefits)		
Operator Hours/Day	4.00	hours/day*		* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SCR Cost Development Methodology, Chapter 5, Attachment 5-3, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-3_scr_cost_development_methodology.pdf	Refer to the *Utility Chem$ Data* tab
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	Refer to the *Utility Chem$ Data* tab
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	Average of 2015-2019 data
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	Average of 2015-2019 data
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	Refer to the *Utility Chem$ Data* tab

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	472	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	452,166,084	lbs/year
Actual Annual fuel consumption (Mactual) =		323,950,000	lbs/year
Heat Rate Factor (HRF) =	NPHR/10 =	1.00	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.716	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	7,536	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	89.6	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	203.13	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	812.46	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.12	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	209,000	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	96.78	/hour
Residence Time	1/V_{space}	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.04	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.1	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.50	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	2,159.47	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	218	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	250	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	15.8	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	54	feet

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	139	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	278	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	29	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	9,900	gallons (storage needed to store a 14 day reagent supply rounded to

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0837

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	270.15	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$20,134,912	in 2020 dollars
Reagent Preparation Cost (RPC) =	$3,581,809	in 2020 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2020 dollars
Balance of Plant Costs (BPC) =	$4,769,432	in 2020 dollars
Total Capital Investment (TCI) =	$37,031,999	in 2020 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) = $20,134,912 in 2020 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) = $3,581,809 in 2020 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) = $0 in 2020 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529{,}000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) = $4,769,432 in 2020 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$960,949 in 2020 dollars
Indirect Annual Costs (IDAC) =	$3,104,345 in 2020 dollars
Total annual costs (TAC) = DAC + IDAC	$4,065,293 in 2020 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$185,160 in 2020 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$400,990 in 2020 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$162,055 in 2020 dollars
Annual Catalyst Replacement Cost =		$212,743 in 2020 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost		
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x $(CC_{replace}/R_{layer})$ x FWF	* Calculation Method 2 selected.
Method 2 (for coal-fired industrial boilers):	$(Q_B/NPHR)$ x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x $(CC_{replace})$ x 35.3	
Direct Annual Cost =		$960,949 in 2020 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$4,766 in 2020 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$3,099,578 in 2020 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$3,104,345 in 2020 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$4,065,293 per year in 2020 dollars
NOx Removed =	812 tons/year
Cost Effectiveness =	$5,004 per ton of NOx removed in 2020 dollars

^^^Does not include reheat costs

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 5: NO_x Control - Low NOx Burners (LNB) Coal-Fired

Operating Unit: **Boiler 1**

Emission Unit Number	EQUI17		Stack/Vent Number	STRU25	
Desgin Capacity	472	MMBtu/hr	Standardized Flow Rate	123,889	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	370	Deg F
Expected Annual Hours of Operation	7,536	Hours	Moisture Content	11.8%	
Annual Interest Rate	5.5%		Actual Flow Rate	209,000	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	132,954	scfm @ 68º F
			Dry Std Flow Rate	117,332	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Cost^{s}								
Purchased Equipment (A$^{)}$								**727,000**
Purchased Equipment Total (B$^{)}$	22%	of control device cost (A)						**886,031**
Installation - Standard Costs	0%	of purchased equip cost (B)						710,900
Installation - Site Specific Cost^{s}								0
Installation Tota^{l}								710,900
Total Direct Capital Cost, DC								1,596,931
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)						460,736
Total Capital Investment (TCI) = DC + IC								**2,057,668**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						100,192
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						441,851
Total Annual Cost (Annualized Capital Cost + Operating Cost								**542,043**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Cont. Emis. lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10		-			-	NA
Total Particulates		-			-	NA
Nitrous Oxides (NOx)	906.9	212.6	**0.45**	801.0	105.9	5,117
Sulfur Dioxide (SO_2)		-			-	NA

Notes & Assumptions

1 Purchased equipment and installation costs from vendor

2 Assumed 0.5 hr/shift operatior and maintenance labor for LNB

3 Controlled emission factor based on vendor estimated burner performance

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 5: NOx Control - Low NOx Burners (LNB) Coal-Fired

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**727,000**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	72,700
MN Sales Taxes	6.9%	of control device cost (A)	49,981
Freight	5%	of control device cost (A)	36,350
Purchased Equipment Total (B)	22%		**886,031**
Installation [1]			
Foundations & supports	0%	of purchased equip cost (B)	0
Handling & erection	0%	of purchased equip cost (B)	0
Electrical	0%	of purchased equip cost (B)	0
Piping	0%	of purchased equip cost (B)	0
Insulation	0%	of purchased equip cost (B)	0
Painting	0%	of purchased equip cost (B)	0
Installation Subtotal Standard Expenses	0%		**710,900**
Installation Total			**710,900**
Total Direct Capital Cost, DC			**1,596,931**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	88,603
Construction & field expenses	20%	of purchased equip cost (B)	177,206
Contractor fees	10%	of purchased equip cost (B)	88,603
Start-up	1%	of purchased equip cost (B)	8,860
Performance test	1%	of purchased equip cost (B)	8,860
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	10%	of purchased equip cost (B)	88,603
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**460,736**
Total Capital Investment (TCI) = DC + IC			**2,057,668**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	
Total Site Specific Costs			**0**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cos			**2,057,668**
Total Capital Investment (TCI) with Retrofit Factor	50%		**3,086,501**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	67.53	$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr	31,807
Supervisor	15%	15% of Operator Costs	4,771
Maintenance (2)			
Maintenance Labor	67.53	$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr	31,807
Maintenance Materials	100%	of maintenance labor costs	31,807
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**100,192**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	60,115
Administration (2% total capital costs)	2%	of total capital costs (TCI)	61,730
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	30,865
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	30,865
Capital Recovery	8%	for a 20- year equipment life and a 5.5% interest rate	258,276
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cos	**441,851**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**542,043**

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 5: NOx Control - Low NOx Burners (LNB) Coal-Fired

Capital Recovery Factors

Primary Installation

Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:

N/A

Replacement Parts & Equipment:

N/A

Electrical Use

Reagent Use & Other Operating Costs

Operating Cost Calculations

Annual hours of operation: **7,536**

Utilization Rate: **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	67.53	$/Hr	0.5	hr/8 hr shift	471	31,807	$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr
Supervisor	15%	of Op.			NA	4,771	15% of Operator Costs
Maintenance							
Maint Labor	67.53	$/Hr	0.5	hr/8 hr shift	471	31,807	$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	31,807	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.080	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 7536 hr/yr, 100% utilization
Natural Gas	3.90	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 7536 hr/yr, 100% utilization
Water	5.13	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7536 hr/yr, 100% utilization

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 6: NO_x Control - Low NOx Burners (LNB) with Over-Fire Air (OFA) Coal-Fired

Operating Unit: **Boiler 1**

Emission Unit Number	EQUI17		Stack/Vent Number	STRU25	
Desgin Capacity	472	MMBtu/hr	Standardized Flow Rate	123,889	scfm @ 32º F
Expected Utiliztion Rate	100%		Temperature	370	Deg F
Expected Annual Hours of Operatior	7,536	Hours	Moisture Content	11.8%	
Annual Interest Rate	5.5%		Actual Flow Rate	209,000	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	132,954	scfm @ 68º F
			Dry Std Flow Rate	117,332	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Cost S								
Purchased Equipment (A)								**1,265,871**
Purchased Equipment Total (B)	22%	of control device cost (A)						**1,542,780**
Installation - Standard Costs	0%	of purchased equip cost (B)						1,215,900
Installation - Site Specific Cost S								0
Installation Tota l								1,215,900
Total Direct Capital Cost, DC								2,758,680
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)						802,246
Total Capital Investment (TCI) = DC + IC								**3,560,926**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						100,192
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						720,734
Total Annual Cost (Annualized Capital Cost + Operating Cost								**820,926**

Emission Control Cost Calculation

Pollutant	**Baseline Emis. T/yr**	**Cont. Emis. lb/hr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10		-			-	NA
Total Particulates		-			-	NA
Nitrous Oxides (NOx)	906.9	179.5	**0.38**	676.4	230.5	3,561
Sulfur Dioxide (SO_2)		-			-	NA

Notes & Assumptions

1 Purchased equipment and installation costs from vendor
2 Assumed 0.5 hr/shift operatior and maintenance labor for LNB
3 Controlled emission factor based on vendor estimated burner/OFA performance

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 6: NOx Control - Low NOx Burners (LNB) with Over-Fire Air (OFA) Coal-Fired

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**1,265,871**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	126,587
MN Sales Taxes	6.9%	of control device cost (A)	87,029
Freight	5%	of control device cost (A)	63,294
Purchased Equipment Total (B)	22%		**1,542,780**
Installation [1]			
Foundations & supports	0%	of purchased equip cost (B)	0
Handling & erection	0%	of purchased equip cost (B)	0
Electrical	0%	of purchased equip cost (B)	0
Piping	0%	of purchased equip cost (B)	0
Insulation	0%	of purchased equip cost (B)	0
Painting	0%	of purchased equip cost (B)	0
Installation Subtotal Standard Expenses	0%		**1,215,900**
Installation Total			**1,215,900**
Total Direct Capital Cost, DC			**2,758,680**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	154,278
Construction & field expenses	20%	of purchased equip cost (B)	308,556
Contractor fees	10%	of purchased equip cost (B)	154,278
Start-up	1%	of purchased equip cost (B)	15,428
Performance test	1%	of purchased equip cost (B)	15,428
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	10%	of purchased equip cost (B)	154,278
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**802,246**
Total Capital Investment (TCI) = DC + IC			**3,560,926**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	
Total Site Specific Costs			**0**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cos			**3,560,926**
Total Capital Investment (TCI) with Retrofit Factor	50%		**5,341,389**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	67.53	$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr	31,807
Supervisor	15%	15% of Operator Costs	4,771
Maintenance (2)			
Maintenance Labor	67.53	$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr	31,807
Maintenance Materials	100%	of maintenance labor costs	31,807
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**100,192**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	60,115
Administration (2% total capital costs)	2%	of total capital costs (TCI)	106,828
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	53,414
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	53,414
Capital Recovery	8%	for a 20- year equipment life and a 5.5% interest rate	446,964
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cos	**720,734**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**820,926**

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 6: NOx Control - Low NOx Burners (LNB) with Over-Fire Air (OFA) Coal-Fired

Capital Recovery Factors

Primary Installation

Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:

N/A

Replacement Parts & Equipment:

N/A

Electrical Use

Reagent Use & Other Operating Costs

Operating Cost Calculations

Annual hours of operation: **7,536**
Utilization Rate: **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	67.53	$/Hr	0.5	hr/8 hr shift	471	31,807	$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr
Supervisor	15%	of Op.			NA	4,771	15% of Operator Costs
Maintenance							
Maint Labor	67.53	$/Hr	0.5	hr/8 hr shift	471	31,807	$/Hr, 0.5 hr/8 hr shift, 7536 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	31,807	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.080	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 7536 hr/yr, 100% utilization
Natural Gas	3.90	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 7536 hr/yr, 100% utilization
Water	5.13	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 7536 hr/yr, 100% utilization

Air Pollution Control Cost Estimation Spreadsheet
For Selective Non Catalytic Reduction (SNCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Non-Catalytic Reduction (SNCR) control device. SNCR is a post-combustion control technology for reducing NOx emissions by injecting an ammonia-base reagent (urea or ammonia) into the furnace at a location where the temperature is in the appropriate range for ammonia radicals to react with NOx to form nitrogen and water.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SNCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SNCR control technology and the cost methodologies, see Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SNCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM version 6). The size and costs of the SNCR are based primarily on four parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, and the reagent consumption. This approach provides study-level estimates (±30%) of SNCR capital and annual costs. Default data in the spreadsheet is taken from the SNCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions, such as the boiler configuration and fuel type. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will reset the NSR, plant elevation, estimated equipment life, desired dollar year, cost index (to match desired dollar year), annual interest rate, unit costs for fuel, electricity, reagent, water and ash disposal, and the cost factors for maintenance cost and administrative charges. All other data entry fields will be blank.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SNCR is for new construction or retrofit of an existing boiler. 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.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you selected coal, select the type of coal burned from the drop down menu. The NOx emissions rate, weight percent coal ash and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided.

Step 4: Complete all of the cells highlighted in yellow. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.015 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SNCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SNCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?	Industrial ▼
Is the SNCR for a new boiler or retrofit of an existing boiler?	Retrofit ▼
Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.	1.5
What type of fuel does the unit burn?	Coal ▼

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	472.4 MMBtu/hour
What is the higher heating value (HHV) of the fuel?	9,152 Btu/lb
What is the estimated actual annual fuel consumption?	323,950,000
Is the boiler a fluid-bed boiler?	No ▼
Enter the net plant heat input rate (NPHR)	10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

coal burned: Sub-Bituminous ▼

Enter the sulfur content (%S) =

or

Select the appropriate SO_2 emission rate: Not Applicable ▼

Ash content (%Ash): percent by weight

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Number of days the SNCR operates (t_{SNCR})	314 days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.48 lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.30 lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.30
Plant Elevation	1,100 Feet above sea level

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

Concentration of reagent as stored (C_{stored})	50 Percent
Density of reagent as stored (ρ_{stored})	71 lb/ft^3
Concentration of reagent injected (C_{inj})	10 percent
Number of days reagent is stored ($t_{storage}$)	14 days
Estimated equipment life	20 Years
	Urea ▼

Densities of typical SNCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Enter the cost data for the proposed SNCR:

Desired dollar-year	2020				
CEPCI for 2020	607.5	2019 Final CEPCI Value	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.50	Percent*			
Fuel (Cost$_{fuel}$)	2.13	$/MMBtu			
Reagent (Cost$_{reag}$)	1.81	$/gallon for a 50 percent solution of urea			
Water (Cost$_{water}$)	0.0051	$/gallon			
Electricity (Cost$_{elect}$)	0.0796	$/kWh			
Ash Disposal (for coal-fired boilers only) (Cost$_{ash}$)	63.34	$/ton			

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	Refer to the *Utility Chem$ Data* tab
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	Refer to the *Utility Chem$ Data* tab
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	Refer to the *Utility Chem$ Data* tab
Fuel Cost ($/MMBtu)	1.89	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	Refer to the *Utility Chem$ Data* tab
Ash Disposal Cost ($/ton)	48.8	Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft Demand. July 11, 2017. Available at: http://www.wastebusinessjournal.com/news/wbj20170711A.htm.	Refer to the *Utility Chem$ Data* tab
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	Average of 2015-2019 data
Percent ash content for Coal (% weight)	5.84	Average ash content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	Used default
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	Average of 2015-2019 data
Interest Rate (%)	5.5	Default bank prime rate	Used default

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	472	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	452,166,084	lbs/year
Actual Annual fuel consumption (Mactual) =		323,950,000	lbs/year
Heat Rate Factor (HRF) =	NPHR/10 =	1.00	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.62	fraction
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	7536	hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	38	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	85.03	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	340.10	tons/year
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO_2 Emission rate =	(%S/100)x(64/32)*(1x10^6)/HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.04	
Atmospheric pressure at 1100 feet above sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.1	psia
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used Urea

Molecular Weight of Reagent (MW) = 60.06 g/mole

Density = 71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	192	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	384	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	40.4	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	13,600	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0837

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	13.8	kW/hour
Water Usage: Water consumption (q_w) =	$(m_{sol}/\text{Density of water}) \times ((C_{stored}/C_{inj}) - 1)$ =	184	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	1.55	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1x10^6)/HHV$ =	9.9	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$2,040,438 in 2020 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2020 dollars
Balance of Plant Costs (BOP_{cost}) =	$3,274,167 in 2020 dollars
Total Capital Investment (TCI) =	$6,908,987 in 2020 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$2,040,438 in 2020 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2020 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$3,274,167 in 2020 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$699,187 in 2020 dollars
Indirect Annual Costs (IDAC) =	$581,391 in 2020 dollars
Total annual costs (TAC) = DAC + IDAC	$1,280,578 in 2020 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$103,635 in 2020 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$552,860 in 2020 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$8,291 in 2020 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$7,111 in 2020 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$24,922 in 2020 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$2,368 in 2020 dollars
Direct Annual Cost =		$699,187 in 2020 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$3,109 in 2020 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$578,282 in 2020 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$581,391 in 2020 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,280,578 per year in 2020 dollars
NOx Removed =	340 tons/year
Cost Effectiveness =	$3,765 per ton of NOx removed in 2020 dollars

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 7: SO2 Control Spray Dry Absorber (SDA) with Baghouse (including lime slaking system)

Operating Unit: **Boiler 1**

Emission Unit Number	EQUI17		Stack/Vent Number	STRU25	
Design Capacity	472	MMBtu/hr	Standardized Flow Rate	123,889	scfm @ 32º F
Utilization Rate	100%		Temperature	370	Deg F
Annual Operating Hours	7,536	Hours	Moisture Content	11.8%	
Annual Interest Rate	5.5%		Actual Flow Rate	209,000	acfm
Equipment Life	20	yrs	Standardized Flow Rate	132,954	scfm @ 68º F
			Dry Std Flow Rate	117,332	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Cost								
Purchased Equipment (A)								**20,384,880**
Purchased Equipment Total (B	22%	of control device cost (A						**24,844,072**
Installation - Standard Costs	74%	of purchased equip cost (B)						18,384,613
Installation - Site Specific Costs								NA
Installation Total								18,384,613
Total Direct Capital Cost, DC								43,228,685
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)						12,918,917
Total Capital Investment (TCI) = DC + IC								**56,147,603**
Adjusted TCI for Replacment Parts								**55,294,650**
TCI with Retrofit Factor								**82,941,976**
Operating Costs								
Total Annual Direct Operating Cost		Labor, supervision, materials, replacement parts, utilities, et						1,086,037
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						10,622,073
Total Annual Cost (Annualized Capital Cost + Operating Cost								**11,708,110**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc.**	**Conc. Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10						0.0	-	NA
PM2.5						0.0	-	NA
Total Particulates						0.0	-	NA
Nitrous Oxides (NOx)						0.0	-	NA
Sulfur Dioxide (SC$_2$)		785.8	90%			78.6	707.2	16,556
Sulfuric Acid Mist						0.00	-	NA
Fluorides						0.0	-	NA
Volatile Organic Compounds (VOC)						0.0	-	NA
Carbon Monoxide (CO)						0.0	-	NA
Lead (Pb)						0.00	-	NA

Notes & Assumptions

1. Capital cost estimate based on flow rate of 300,000 scfm from Northshore Mining Powerhouse #2 2006 BART submittal including anciliary equipment
2. Costs scaled up to design airflow using the 6/10 power law
3. Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 7: SO2 Control Spray Dry Absorber (SDA) with Baghouse (including lime slaking system)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A)(1)			**20,384,880**
Purchased Equipment Costs (A) - Absorber + packing + auxiliary equipment, EC			
Instrumentatior	10%	of control device cost (A	2,038,488
State Sales Taxes	6.9%	of control device cost (A)	1,401,460
Freight	5%	of control device cost (A	1,019,244
Purchased Equipment Total (B)	22%		**24,844,072**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	993,763
Handling & erection	50%	of purchased equip cost (B)	12,422,036
Electrical	8%	of purchased equip cost (B	1,987,526
Piping	1%	of purchased equip cost (B)	248,441
Insulation	7%	of purchased equip cost (B	1,739,085
Painting	4%	of purchased equip cost (B)	993,763
Installation Subtotal Standard Expenses	74%		**18,384,613**
Other Specific Costs (see summary)			
Site Preparation, as required	N/A	Site Specific	-
Buildings, as required	N/A	Site Specific	-
Site Specific - Other	N/A	Site Specific	-
Total Site Specific Costs			NA
Installation Total			**18,384,613**
Total Direct Capital Cost, DC			**43,228,685**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B	2,484,407
Construction & field expenses	20%	of purchased equip cost (B)	4,968,814
Contractor fees	10%	of purchased equip cost (B	2,484,407
Start-up	1%	of purchased equip cost (B)	248,441
Performance test	1%	of purchased equip cost (B)	248,441
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	2,484,407
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B	**12,918,917**
Total Capital Investment (TCI) = DC + IC			**56,147,603**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cos			**55,294,650**
Total Capital Investment (TCI) with Retrofit Factor	50%		**82,941,976**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	67.53	$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr	127,228
Supervisor	15%	15% of Operator Costs	19,084
Maintenance			
Maintenance Labor	67.53	$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr	63,614
Maintenance Materials	100%	of maintenance labor costs	63,614
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.08	$/kwh, 378.3 kW-hr, 7536 hr/yr, 100% utilization	226,923
Compressed Air	0.48	$/kscf, 2.0 scfm/kacfm, 7536 hr/yr, 100% utilization	90,981
N/A			-
SW Disposal	63.34	$/ton, 0.2 ton/hr, 7536 hr/yr, 100% utilization	99,558
Lime	183.68	$/ton, 282.2 lb/hr, 7536 hr/yr, 100% utilization	195,295
Filter Bags	228.02	$/bag, 3,072 bags, 7536 hr/yr, 100% utilization	199,741
N/A			-
N/A			-
N/A			-
N/A			-
N/A			-
N/A			-
N/A			-
Total Annual Direct Operating Costs			**1,086,037**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	164,123
Administration (2% total capital costs)	2%	of total capital costs (TCI)	1,658,840
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	829,420
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	829,420
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	7,140,270
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cos	**10,622,073**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**11,708,110**

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 7: SO2 Control Spray Dry Absorber (SDA) with Baghouse (including lime slaking system)

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:	**Filter Bags**		
Equipment Life	5	years	
CRF	0.2342		
Rep part cost per unit	228.02	$/bag	
Amount Required	3072		
Total Rep Parts Cost	783,794	Cost adjusted for freight & sales tax	
Installation Labo	69,158	10 min per bag, Labor + Overhead (68% = $29.65/h	EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.
Total Installed Cost	**852,952**	**Zero out if no replacement parts needed**	lists replacement times from 5 - 20 min per bag.
Annualized Cos	**199,741**		

Electrical Use

	Flow acfm	D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	209,000	10.00			2,850,793	Incremental electricity increase over with baghouse replacin scrubber including ducting
Total					2,850,793	

Reagents and Other Operating Costs

Lime Use Rate	1.30	lb-mole CaO/lb-mole SO2	282.17	lb/hr Lime
Solid Waste Disposal	1,572	ton/yr GSA unreacted sorbent and reaction byproducts		

Operating Cost Calculations

Utilization Rate	100%	Annual Operating Hours	7,536				
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	1,884	$ 127,228	$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr
Supervisor	15%	of Op.			NA	$ 19,084	15% of Operator Costs
Maintenance							
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	942	$ 63,614	$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	$ 63,614	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.080	$/kwh	378.3	kW-hr	2,850,793	$ 226,923	$/kwh, 378.3 kW-hr, 7536 hr/yr, 100% utilization
Compressed Air	0.481	$/kscf	2	scfm/kacfm	189,003	$ 90,981	$/kscf, 2.0 scfm/kacfm, 7536 hr/yr, 100% utilization
Water	5.129	$/mgal		gpm			$/mgal, 0 gpm, 7536 hr/yr, 100% utilization
SW Disposal	63.34	$/ton	0.21	ton/hr	1,572	$ 99,558	$/ton, 0.2 ton/hr, 7536 hr/yr, 100% utilization
Lime	183.68	$/ton	282.2	lb/hr	1,063	$ 195,295	$/ton, 282.2 lb/hr, 7536 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	3,072	bags	N/A	$ 199,741	$/bag, 3,072 bags, 7536 hr/yr, 100% utilization

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 8: SO2 Control Dry Sorbent Injection (DSI) with Baghouse (including injection system)

Operating Unit: **Boiler 1**

Emission Unit Number			Stack/Vent Number		
Design Capacity	472	MMBtu/hr	Standardized Flow Rate	123,889	scfm @ 32º F
Utilization Rate	100%		Exhaust Temperature	370	Deg F
Annual Operating Hours	7,536	hr/yr	Exhaust Moisture Content	11.8%	
Annual Interest Rate	5.50%		Actual Flow Rate	209,000	acfm
Control Equipment Life	20	yrs	Standardized Flow Rate	132,954	scfm @ 68º F
Plant Elevation	1100	ft	Dry Std Flow Rate	117,332	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs						
Direct Capital Costs						
Purchased Equipment (A)						**9,026,849**
Purchased Equipment Total (B)	22%	of control device cost (A)				**11,001,473**
Installation - Standard Costs	74%	of purchased equip cost (B)				8,141,090
Installation - Site Specific Costs						N/A
Installation Total						8,141,090
Total Direct Capital Cost, DC						19,142,562
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)				5,720,766
Total Capital Investment (TCI) = DC + IC						**24,010,376**
Adjusted TCI for Replacement Parts						24,010,376
Total Capital Investment (TCI) with Retrofit Factor						**36,015,563**
Operating Costs						
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc				2,166,769
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost				4,818,246
Total Annual Cost (Annualized Capital Cost + Operating Cost)						**6,985,015**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual Ton/Yr**	**Cont Eff %**	**Cont Emis Ton/Yr**	**Reduction Ton/Yr**	**Cont Cost $/Ton Rem**
PM10						
PM2.5						
Total Particulates						
Nitrous Oxides (NOx)						
Sulfur Dioxide (SO2)	208.54	785.76	70%	235.73	550.03	$12,700
Sulfuric Acid Mist (H2SO4)						
Fluorides						
Volatile Organic Compounds (VOC)						
Carbon Monoxide (CO)						
Lead (Pb)						

Notes & Assumptions

1 Capital cost estimate based on flow rate of 300,000 scfm from Northshore Mining Powerhouse #2 2006 BART submittal including anciliary equipment
2 Costs scaled up to design airflow using the 6/10 power law
3 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 8: SO2 Control Dry Sorbent Injection (DSI) with Baghouse (including injection system)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) [(1)]			**9,026,849**
Purchased Equipment Costs (A) - Injection System + auxiliary equipment, EC			
Instrumentation	10%	Included in vendor estimate	902,685
State Sales Taxes	6.9%	of control device cost (A)	620,596
Freight	5%	of control device cost (A)	451,342
Purchased Equipment Total (B)	22%		**11,001,473**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	440,059
Handling & erection	50%	of purchased equip cost (B)	5,500,736
Electrical	8%	of purchased equip cost (B)	880,118
Piping	1%	of purchased equip cost (B)	110,015
Insulation	7%	of purchased equip cost (B)	770,103
Painting	4%	Included in vendor estimate	440,059
Installation Subtotal Standard Expenses	74%		**8,141,090**
Other Specific Costs (see summary)			
Site Preparation, as required	N/A	Site Specific	
Buildings, as required	N/A	Site Specific	
Lost Production for Tie-In	N/A	Site Specific	
Total Site Specific Costs			N/A
Installation Total			**8,141,090**
Total Direct Capital Cost, DC			**19,142,562**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	1,100,147
Construction & field expenses	20%	of purchased equip cost (B)	2,200,295
Contractor fees	10%	of purchased equip cost (B)	1,100,147
Start-up	1%	of purchased equip cost (B)	110,015
Performance test	1%	of purchased equip cost (B)	110,015
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	1,100,147
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**5,720,766**
Total Capital Investment (TCI) = DC + IC			**24,863,328**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**24,010,376**
Total Capital Investment (TCI) with Retrofit Factor	50%		**36,015,563**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	67.53	$/Hr	127,228
Supervisor	0.15	of Op Labor	19,084
Maintenance			
Maintenance Labor	67.53	$/Hr	63,614
Maintenance Materials	100	% of Maintenance Labor	63,614
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.08	$/kwh, 227.0 kW-hr, 7536 hr/yr, 100% utilization	136,154
N/A			-
Compressed Air	0.48	$/kscf, 2.0 scfm/kacfm, 7536 hr/yr, 100% utilization	90,981
N/A			-
Solid Waste Disposal	63.34	$/ton, 0.5 ton/hr, 7536 hr/yr, 100% utilization	222,137
Trona	285.00	$/ton, 1,158.6 lb/hr, 7536 hr/yr, 100% utilization	1,244,217
Filter Bags	228.02	$/bag, 3,072 bags, 7536 hr/yr, 100% utilization	199,741
N/A			-
N/A			-
N/A			-
N/A			-
Total Annual Direct Operating Costs			**2,166,769**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	164,123
Administration (2% total capital costs)	2%	of total capital costs (TCI)	720,311
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	360,156
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	360,156
Capital Recovery	0.0837	for a 20-year equipment life and a 5.5% interest rate	3,013,758
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery costs	**4,818,246**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**6,985,015**

Southern Minnesota Beet Sugar Coop (SMBSC)
Appendix A - Four-Factor Control Cost Analysis
Table 8: SO2 Control Dry Sorbent Injection (DSI) with Baghouse (including injection system)

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:	**Filter Bags**	
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	228.02	$/bag
Amount Required	3072	Bags
Total Rep Parts Cost	783,794	Cost adjusted for freight, sales tax, and bag disposal
Installation Labor	69,158	20 min per bag
Total Installed Cost	**852,952**	
Annualized Cost	**199,741**	

Electrical Use

	Flow acfm	D P in H2O	kWhr/yr	
Blower	209,000	6.00	1,710,476	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total			1,710,476	

Reagent Use & Other Operating Costs

Trona use - 1.5 NSR	208.54	lb/hr SO2	1158.62	lb/hr Trona
Solid Waste Disposal	3,507	ton/yr DSI unreacted sorbent and reaction byproducts		

Operating Cost Calculations

Utilization Rate	100%	Annual Operating Hours	7,536

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	1,884	$ 127,228	$/Hr, 2.0 hr/8 hr shift, 1,884 hr/yr
Supervisor	15%	of Op Labor			NA	$ 19,084	% of Operator Costs
Maintenance							
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	942	$ 63,614	$/Hr, 1.0 hr/8 hr shift, 942 hr/yr
Maint Mtls	100%	of Maintenance Labor			NA	$ 63,614	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.080	$/kwh	227.0	kW-hr	1,710,476	$ 136,154	$/kwh, 227.0 kW-hr, 7536 hr/yr, 100% utilization
Water			N/A	gpm			
Compressed Air	0.481	$/kscf	2.0	scfm/kacfm	189,003	$ 90,981	$/kscf, 2.0 scfm/kacfm, 7536 hr/yr, 100% utilization
Cooling Water			N/A	gpm			
Solid Waste Disposal	63.34	$/ton	0.5	ton/hr	3,507	$ 222,137	$/ton, 0.5 ton/hr, 7536 hr/yr, 100% utilization
Trona	285.00	$/ton	1,158.6	lb/hr	4,366	$ 1,244,217	$/ton, 1,158.6 lb/hr, 7536 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	3,072	bags	N/A	$ 199,741	$/bag, 3,072 bags, 7536 hr/yr, 100% utilization

Southern Minnesota Beet Sugar Cooperative
83550 County Road 21, Renville, Minnesota 56284

July 23, 2021

Hassan Bouchareb
Minnesota Pollution Control Agency
520 Lafayette Road N
St. Paul, MN 55155

Re: Responses to MPCA/EPA/FLM Four Factor Analysis Comments

Dear Mr. Bouchareb:

Southern Minnesota Beet Sugar Cooperative (SMBSC) submitted a Regional Haze Four-Factor Analysis (FFA) on July 31, 2020 for Boiler No. 1 (Boiler 1, EQUI 17). The FFA will be used by Minnesota Pollution Control Agency (MPCA) to inform decisions for the Regional Haze State Implementation Plan (SIP) regarding what emission reductions are necessary to make reasonable progress. This letter is in response to the June 8, 2021 email, which provided comments on the FFA.

This memorandum provides responses to the June 8, 2021 comment email. Comments were provided by the MPCA, the U.S. Environmental Protection Agency (EPA), and the Federal Land Managers (FLMs). Bold headings below summarize the essence of the applicable comment(s). The detailed comment email from MPCA is included in Attachment A for reference.

1 Basis for the Selected Retrofit Factor[1]

SMBSC applied a retrofit factor of 1.5 for the control cost analysis, which is appropriate. The justification for this value was listed in sections 5.2 and 6.2 of the original FFA. In addition to the FFA discussion, SMBSC provided additional detail below.

- Any retrofit of pollution controls to Boiler 1 would be extremely difficult and costly. The spaces on the west, north, and east sides of the boiler house support frequent vehicle traffic and cannot be blocked so cranes can conduct maintenance on existing equipment. Regardless, there is no space for new equipment in these areas. Rail lines back up to the south side of Boiler 1, blocking this area for new controls. Therefore, any new equipment would have to be installed on the roof within a constrained footprint or in place of the existing electrostatic precipitator (ESP), which is located above grade and housed within a building.

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[1] MPCA Comment 2, FLM Comment 2a and 3a, EPA Comment 3a (Attachment A)

- The project would require significant amounts of work at heights for the duration of the project, which would significantly slow down the efforts adding cost. The existing ESP would need to be demolished prior to the construction of controls with new particulate devices. Additionally, the existing structural steel may need to be replaced or upgraded to support new controls. Further, as noted above, space surrounding the boiler on all sides is cramped, which would impede any crane activity.

- The condition of existing equipment may present unique challenges that would increase the retrofit cost (e.g., conditions of structural supports). Retrofits to older equipment can be challenging as Boiler 1 was installed in 1972.

- Transporting new materials to the construction area would be slow because the boiler house can only be accessed on the west and east sides through narrow roadways supporting plant equipment and operations

- The complexity of a pollution control technology retrofit described above is anticipated to require a significant amount of downtime compared to greenfield site installation, increasing the overall retrofit cost.

2 Basis for the 5.5% Interest Rate[2]

FLMs and the EPA stated that a firm specific interest rate should be used or the default prime bank rate. The EPA Control Cost Manual (CCM)[3] states that interest rates should reflect firm-specific borrowing rates, but SMBSC cannot provide this information because it is considered as confidential business information. EPA's CCM also states that "*…if firm-specific nominal interest rates are not available, then the bank prime rate can be an appropriate estimate for interest rates*

However, interest rates can fluctuate significantly over time based on economic conditions. As shown in Figure 1, the bank prime rate can frequently change and the current rate of 3.25% is historically a low value. For example, the bank prime rate was at 5.5% as recently as July 2019 and was at 4.75% in February 2020 before dropping to the current 3.25% in April 2020.

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[2] FLM Comments 2d and 3c, EPA Comment 3b (Attachment A)

[3] EPA, Control Cost Manual, 7th Edition

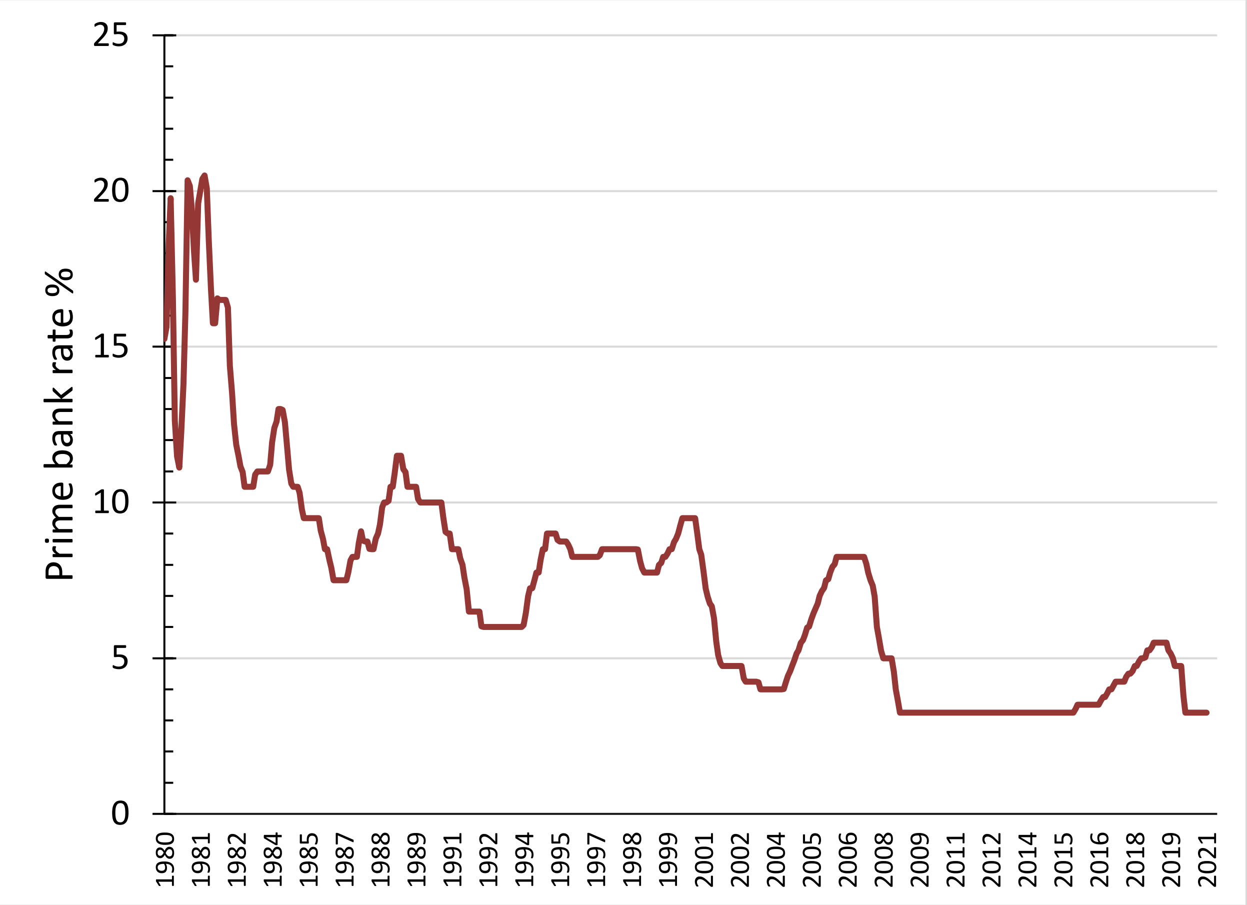

Figure 1 1980-2021 Prime Bank Rate

Although the prime bank rate may be 3.25% today, there is no certainty that this rate will remain constant in the future. Therefore, SMBSC used a 5.5% interest rate in the control cost calculations. This is justified because of the recent and historic volatility in the bank prime rate and the uncertainty that would occur before financing a potential emission reduction project for startup by 2028.[4]

3 Basis for Inclusion of Sales and Property Taxes[5]

FLMs asked if Minnesota levied taxes for pollution control projects. SMBSC will include taxes in the control cost calculations unless the MPCA provides a written agreement that guarantees exemption for any pollution control projects related to the FFA including sales and property

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[4] MPCA has stated that emission reduction projects identified in the 2021 SIP update must be installed prior to the next SIP update in 2028.

[5] FLM Comment 4d (Attachment A)

taxes. These costs can represent a significant expense and SMBSC cannot be expected to exclude taxes from the FFA without a binding agreement by the MPCA.

4 Control Cost Spreadsheet Manual Override[6]

The FLMs stated that Barr altered the EPA cost spreadsheets for selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) without documentation. Barr made these changes because the inputs to the EPA spreadsheets do not correctly calculate the actual emissions reduction (based on SMBSC's 2028 projection). Any manual alterations to the EPA spreadsheets will be noted in future submittals by SMBSC.

5 2028 Projection NO_X Emissions Basis[7]

The FLMs stated "2017 NEI SO_2 and NO_X emissions are greater than 2016 and assumed for 2028." SMBSC developed the 2028 projected emission rate in accordance with EPA guidance,[8] which states "*Generally, the estimate of a source's 2028 emissions is based at least in part on information on the **source's operation and emissions during a representative historical period**.*" Therefore, the proposed emission rates are appropriate.

6 Inlet NO_X Emissions Basis[9]

The FLMs stated that the inlet NO_X emission rate for the SCR analysis was slightly underestimated. However, the value was based on the average of 2015-2019 continuous emissions monitoring system (CEMS) data. Therefore, the value is appropriate.

7 2020 Reagent, Utility, and Labor Cost Basis[10]

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.

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[6] FLM Comments 2f and 3e (Attachment A)

[7] FLM Comment 1 (Attachment A)

[8] https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf

[9] FLM Comment 2b (Attachment A)

[10] MPCA Comment 3, FLM Comments 2e and 3d (Attachment A)

8 SCR Catalyst and Equipment Life Basis[11]

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.

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.

9 Basis for SCR Reheat[12]

FLMs asked why reheat was included for SCR. SMBSC included a reheat system with the SCR design because the spaces surrounding the boiler lack sufficient space to install a SCR reactor upstream of the air preheater. Figure 2-1 of the FFA showed a schematic of Boiler 1 to illustrate this concern. SCR cannot be installed prior to the air preheater because there is no extra space surrounding the equipment and SMBSC staff need to access the space for maintenance purposes. Therefore, SMBSC included post-ESP reheat equipment to alleviate this issue. However, either design would result in major add-on retrofit costs as noted in Item 1 above.

10 Basis for SNCR NO_X Removal Efficiency[13]

FLMs asked how the removal efficiency was determined. The SNCR removal efficiency was calculated based on an outlet NO_X emission rate of 0.3 lb/MMBtu. This value is from the example problem in Section 4, Chapter 1 of the CCM[14] because the inlet NO_X concentration is identical to Boiler 1's inlet NO_X concentration.

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[11] FLM Comment 2c (Attachment A)

[12] FLM Comment 2g (Attachment A)

[13] FLM Comment 3b (Attachment A)

[14] https://www.epa.gov/sites/production/files/2017-12/documents/sncrcostmanualchapter7thedition20162017revisions.pdf

11 Revise the SO_2 Control Cost Analysis Based on Information Specific to SMBSC[15]

The MPCA and FLMs stated that SMBSC should base control costs off site-specific vendor quotes or cost models such as the updated CCM. SMBSC calculated the costs for spray dry absorbers (SDAs) and dry sorbent injection (DSI) by scaling historical cost estimates to present day using Chemical Engineering Plant Cost Index (CEPCI) and the six tenths power law to account for capacity differences. The MPCA and FLMs requested SMBSC to provide a site-specific cost estimates or use recent cost models such as the updated CCM.

Inflationary indices (Chemical Engineering Plant Cost Index [CEPCI]) and capacity scaling factors (six tenths power law)[16] used to adjust historical costs to present day and account for capacity differences are commonly practiced by engineers and should be considered reliable. For example, CEPCI is extensively used by the EPA.[17] The Lake Michigan Air Directors Consortium (LADCO) used inflationary estimates in the *Four-Factor Analysis for Regional Haze in the Northern Midwest Class I Areas* to adjust costs exceeding five years beyond the study year.[18] SMBSC is aware that more recent site-specific quotes may represent the most accurate representation of equipment costs from the current year, but the use of CEPCI is not an unreasonable means to adjust costs to present day in the absence of a current vendor quotation. Further, the calculated cost-effectiveness for SDAs and DSI was approximately $16,600 and $12,700/ton of SO_2 removed. These costs are above what may be considered cost effective based on previous cost effectiveness thresholds, thus additional evaluation is unwarranted.

Nonetheless, SMBSC is willing to get a vendor estimate specific to the flue gas characteristics of the facility. SMBSC will provide an updated control cost evaluation for SDAs and DSI by August 23, 2021.

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

The EPA states that the first step in conducting a FFA will be to identify the technically feasible control options. However, USEPA recognizes that "*there is no statutory or regulatory*

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[15] MPCA Comment 1, FLM Comment 4a (Attachment A)

[16] Turton, Richard; et al. 2008. *Analysis, Synthesis, and Design of Chemical Processes* 3rd ed). Pearson College Div; page 183.

[17] EPA, Control Cost Manual, 7th Edition

[18] Amec Foster Wheeler Environment & Infrastructure, Inc. (2015, October 27). Four-Factor Analysis for Regional Haze in the Northern Midwest Class I Areas: Methodology for Source Selection, Evaluation of Control Options, and Four Factor Analysis.

requirement to consider all technically feasible measures or any particular measures."[19] Therefore, SMBSC streamlined the FFA by selecting a reasonable set of technologies that have been installed and proven in practice at sources similar to Boiler 1. SMBSC used the RACT/BACT/LAER Clearinghouse (RBLC) to review possible technologies for evaluation.

A wet flue gas desulfurization scrubber was not considered for the FFA because captured SO_2 would increase sulfate and potentially mercury wastewater loading. A new wastewater stream cannot be discharged to receiving waters without additional wastewater treatment and at the expense of significant amounts of energy.

13 SDA and DSI SO_2 Control Efficiency Basis[20]

The FLMs stated that the SO_2 control efficiencies were underestimated. SMBSC assumes that the FLMs are referencing the updated CCM (Section 5, Chapter 1, April 2021)[21] as the basis for this comment. However, this comment is inappropriate because the updated CCM chapter was not released until after the FFA submittal deadline. 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 (refer to Item 11 above) if applicable.

14 Basis for SO_2 Controls Equipment Life[22]

The FLMs stated that the SO_2 control equipment life was underestimated. SMBSC assumes that the FLMs are referencing the updated CCM (Section 5, Chapter 1, April 2021)[23] as the basis for this comment. However, this comment is inappropriate because the updated CCM chapter was not released until after the FFA submittal deadline. While an SDA may achieve a 30-year

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[19] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, page 29.

[20] FLM Comment 4c (Attachment A)

[21] https://www.epa.gov/sites/production/files/2021-05/documents/wet_and_dry_scrubbers_section_5_chapter_1_control_cost_manual_7th_edition.pdf

[22] FLM Comment 4e (Attachment A)

[23] https://www.epa.gov/sites/production/files/2021-05/documents/wet_and_dry_scrubbers_section_5_chapter_1_control_cost_manual_7th_edition.pdf

equipment life, SMBSC will not estimate costs based on a "best-case" scenario, especially since the equipment may only last 20 years. Further, EPA received several comments to the updated Section 5, Chapter 1 of the CCM that disagreed with a 30-year equipment life. A 20-year equipment life provides a reasonable amortization period that SMBSC could expect for an actual control equipment installation.

The updated CCM Section 5 does not address DSI. However, the major capital component of DSI is a baghouse. Section 6, Chapter 1 of the CCM[24] states that a 20-year equipment life is typical for baghouses. Therefore, the 20-year life for DSI is appropriate.

15 Existing NO_X and SO_2 Control Measures[25]

SMBSC stated that there are no NO_X or SO_2 controls installed on Boiler 1 in the FFA. The EPA commented "It would be helpful to clearly indicate if there are any existing emission control measures, including operational limits or permitted limits, if they are considered necessary to make reasonable progress, and if those measures are or will be included in the SIP or otherwise be federally enforceable and permanent." As noted in the FFA, there are no add-on or combustion-based emission controls for NO_X or SO_2 installed on Boiler 1. In addition, there are no operational limits or permit limits that restrict operations. Any new operational limits are not technically feasible for SMBSC. Further, such restrictions are not needed to make reasonable progress and should not be included in the SIP. Section 7.0 of the FFA noted that the level of emissions along with the distance to the upper Midwest Class I areas indicate that SMBSC is unlikely to be a significant contributor to visibility impairment. Review of wind direction trends and trajectories associated with impacted days further reinforces the minimal potential for contribution by SMBSC. Thus, additional control measures implemented at SMBSC are unlikely to provide a substantial improvement in visibility in the Class I areas. Further, there are other major equipment shutdowns planned in the state,[26] which will have a much more significant impact on regional haze, diminishing any impact SMBSC would have from new pollution controls or operational restrictions.

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[24] https://www.epa.gov/sites/production/files/2020-07/documents/cs6ch1.pdf

[25] EPA Comment 2 (Attachment A)

[26] Xcel Energy - Upper Midwest Integrated Resource Plan 2020-2034

We appreciate your efforts to review the SMBSC FFA. Should you have any questions or comments regarding this submittal, please contact me by telephone at 320-329-4174 or via email at sagar@smbsc.com.

Sincerely,

Sagar Sunkavalli
Manager of Environmental Affairs

Attachment A

Regional Haze: Four Factor Analysis Review/Questions: Southern Minnesota Beet Sugar Cooperative Email

From: Bouchareb, Hassan (MPCA) <hassan.bouchareb@state.mn.us>
Sent: Tuesday, June 8, 2021 10:58 AM
To: Vidyasagar Sunkavalli <Vidyasagar.Sunkavalli@smbsc.com>
Cc: deAlwis, Deepa (MPCA) <deepa.dealwis@state.mn.us>
Subject: Regional Haze :: Four Factor Analysis Review/Questions :: Southern MN Beet Sugar

Good morning Sagar,

Thanks for your patience so far regarding regional haze related efforts. I have reviewed the four factor analyses prepared for Southern Minnesota Beet Sugar Coop and have a few comments. I also wanted to forward comments on the analyses that I received from EPA and the federal land managers (FLMs) from the Forest Service and National Parks Service that I would like to address as well. I've tried to summarize the various requests based on MPCA's review and the comments/requests received from EPA and the FLMs to group them by general area. More detail on these requests is available farther down.

I would like further discuss these comments with you and your team if you have the time available. My intention is to give you a general update on where things are at with respect to the Regional Haze SIP, what is going into the decision-making process for this project, and a brief update on the tentative schedule for preparing and submitting this SIP to EPA for approval.

I'm not sure who all you would like to be at this discussion, but if you let me know a few dates/times that work for your team I'd be happy to make those times work. If you can get back to me within a week (by June 15th) that would be great.

Thanks in advance!

Request Summary:

1. SO_2 controls
    a. Address comments related to cost analysis methodology (MPCA comment 1, FLM comment 4)
2. NO_X controls
    a. Address comments related to cost analysis methodology (MPCA comment 3, FLM comment 2/3)
3. Retrofit Factor
    a. Please provide additional information regarding the choice of retrofit factor and how you arrived at that value (MPCA comment 2a, FLM comment 2a/3a/4b, EPA comment 4a)
4. Interest Rate
    a. Revise control cost estimates to use the current prime interest rate (3.25%) per the control cost manual suggested default or provide supporting documentation to support the 5.5% interest rate used in the current analyses (FLM comment 2d/3c/4f, EPA comment 3b).

Specific Comments (MPCA):

MPCA has the following questions/comments.

1. SO_2 controls
    a. Please revise the SO_2 controls analysis to base capital costs on information specific to Southern Minnesota Beet Sugar instead of the cost estimates from Northshore Mining's 2006 BART analysis

i. Note that there is a SO_2 control cost spreadsheet that is now available from EPA to estimate costs of various SO_2 controls

ii. I suggest that you update the cost estimates to use these spreadsheet now that it is available (first released in May 2021)

2. Retrofit factor
    a. For the analyses, a retrofit factor of 1.5 (50%) is used for cost estimates. The value of retrofit factors used should be supported and documented in the control cost analysis.
    b. Note -- EPA's Control Cost Manual offers some guidance on selecting retrofit factors for various control technologies:

i. SNCR - "A retrofit factor of 0.84 should be used for new construction and a retrofit factor of 1 should be used for SNCR retrofits to existing boilers, where the retrofit is of an average level of difficulty." CCM (7th Edition), Section 4, Chapter 1, page 1-42..

ii. SCR - "A retrofit factor of 0.8 should be used for new construction and a retrofit factor of 1 should be used for average retrofits. … For retrofits that are more complicated than average, a retrofit factor of greater than 1 can be used to estimate capital costs provided the reasons for using a higher retrofit factor are appropriate and fully documented." CCM (7th Edition), Section 4, Chapter 2, page 66 of 107.

iii. SDA/DSI - "A retrofit factor (RF) of 0.77 should be used for new construction and a retrofit factor of 1 should be used for retrofits to existing units, where the retrofit is of an average level of difficulty." CCM (7th Edition), Section 5, Chapter 1, page 1-48.

3. NO_X controls
    a. Regarding the FLM comments focusing on costs for various components (e.g., catalyst life, reagent cost, water cost, etc.), I believe most of the changes noted are due to upscaling costs to 2020 dollars. If not, please provide additional clarification on how you arrived at the values used

Specific Comments (Federal Land Managers - FLMs)

As part of the regional haze program, Federal Land Managers have a more direct role in the development of states' regional haze SIPs. Part of this includes consultation prior to the public notice period of the SIP. MPCA provided the FLMs with the a link to the webpage where the four factor analyses are posted and offered the ability to provide comments and questions on the analyses. Specific comments to the analyses prepared are below:

1. Baseline Emissions:
    a. 2017 NEI SO2 and NOx emissions are greater than 2016 and assumed for 2028.
2. SCR Analysis:
    a. The 1.5 retrofit factor is not justified. Site-specific retrofit factors should be based upon a thorough and well-documented analysis of the individual factors involved in a project. For example, the methods outlined by William Vatavuk on pages 59-62 in his book Estimating Costs of Air Pollution Control be followed. That process involves estimating and assigning a retrofit factor to each major element of a project and from that deriving an overall retrofit factor. The CCM also addresses "Retrofit Cost Considerations" in section 2.6.4.2. In the absence of such a proper analysis, assume a retrofit factor = 1.0, which represents a 30% increase above costs for a "greenfield" project.
    b. Inlet NOx is slightly underestimated.
    c. Catalyst life and SCR life are underestimated relative to the CCM defaults with no justification.
    d. Interest rate should be the current bank prime rate = 3.25% instead of 5.5%.
    e. Reagent cost, water cost, electricity cost, catalyst cost and labor cost all appear to have been inflated from default values with no justification; actual values should be used.
    f. Barr has over-ridden the CCM calculated values for "Total operating time for the SNCR (top)" and "Total NOx removed per year " to reflect actual hours of operation and expected emission reductions. While this is OK, it should have been noted and explained. Instead of altering the internal workings of the workbook, Barr should have adjusted the data inputs to reflect the anticipated emission reductions.
    g. Why is reheat needed for SCR? Can SCR be installed ahead of the air preheater, or some location with suitable temperature?

3. SNCR Analysis:
    a. The 1.5 retrofit factor is not justified (see above).
    b. How was removal efficiency/outlet NOx rate determined?
    c. Interest rate should be the current bank prime rate = 3.25% instead of 5.5%.
    d. Reagent cost, water cost, electricity cost, fuel cost, and ash disposal cost all appear to have been inflated from default values with no justification.
    e. Barr has over-ridden the CCM calculated values for "Total operating time for the SNCR (top)" and "Total NOx removed per year " to reflect actual hours of operation and expected emission reductions. While this is OK, it should have been noted and explained. Instead of altering the internal workings of the workbook, Barr should have adjusted the data inputs to reflect the anticipated emission reductions.
4. SO_2 Controls:
    a. The SO_2 control cost estimates are based upon the Northshore Mining Powerhouse #2 2006 BART submittal and were scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI).

i. According to section 2.5.3 of the CCM: **2.5.3 Prices and Inflation** -- It should be noted that the accuracy associated with escalation (and its reverse, de- escalation) declines the longer the time period over which this is done. Escalation with a time horizon of more than five years is typically not considered appropriate as such escalation does not yield a reasonably accurate estimate. Thus, obtaining new price quotes for cost items is advisable beyond five years. If longer escalation periods are unavoidable due to limited recent cost data that is reasonably available, then the analysis should use the principles in this Manual chapter to provide as accurate an escalation as possible consistent with the Manual given the limitations of the cost analysis. The appropriate length of time for escalation can vary as a result of significant changes in the cost of major production inputs(e.g., energy, steel, chemical reagents, etc.) and technological changes in control measures, particularly if these changes occur in an unusually short period of time. Hence, shorter time periods for escalation and de-escalation are clearly preferred over longer ones.

ii. Instead of using an obsolete vendor quote from a different facility, SMBSC/Barr should provide a new cost estimate using either a current vendor quote for this facility or apply current costing models for DSI, Spray Dry Absorbers, and Wet FGD. (Why was wet FGD omitted from the Barr analysis?) We recommend use of the proposed revision to the SO2 and Acid Gas Control chapter in the CCM or the IPM models (developed by Sargent & Lundy) upon which the proposed CCM revisions are based.

    b. The 1.5 retrofit factor is not justified.
    c. SO2 control efficiencies were underestimated.
    d. Taxes were included. (Does MN levy sales and property taxes on APC equipment?)
    e. Equipment life was underestimated.
    f. Interest rate should be the current bank prime rate = 3.25% instead of 5.5%.

Specific Comments (EPA):

MPCA also provided EPA with the link to the four factor analyses. EPA also provided comments on the collection of four factor analyses prepared. Specific comments to the analyses prepared are below:

1. For Southern Minnesota Beet Coop, Barr evaluated Boiler No. 1 for NOx and SO2 controls and provided a review of the visibility impacts. The four-factor analysis looked at NOx controls (SCR, SNCR, LNB, LNB+OFA) and SO2 controls (SDA, DSI). For NOx, Barr found that the cost effectiveness of reductions ($3600 - $7000/ton) exceeded cost effectiveness stated in EPA's Final TSD for CSAPR, and Barr concluded that none of the evaluated NOx controls were reasonable. For SO2, Barr found that the cost effectiveness of reductions ($12,7000 – $16,600/ton) exceeded cost effectiveness from MPCA's original BART and concluded that none of the SO2 controls were reasonable.
2. The analysis does not mention any existing pollution controls or operational measures other than the high-efficiency electrostatic precipitator (ESP) and the use of sub-bituminous coal. Barr states that there is no control equipment for SO2 or NOx. It would be helpful to clearly indicate if there are any existing emission control measures, including operational limits or permitted limits, if they are considered necessary to make reasonable progress, and if those measures are or will be included in the SIP or otherwise be federally enforceable and permanent.
3. Please see the General Comments above regarding interest rates and retrofit factors for the analysis pertaining to Boiler No. 1.
    a. From the general comments -- Retrofit Factors

i. For example -- For the analyses, a retrofit factor of 1.5 (50%) is used. The value of retrofit factors used should be supported and documented in the control cost analysis. EPA's Control Cost Manual states, "A retrofit factor of 0.84 should be used for new construction and a retrofit factor of 1 should be used for SNCR retrofits to existing boilers, where the retrofit is of an average level of difficulty." CCM (7th Edition), Section 4.2, Chapter 1, page 1-42. It would be helpful to provide support and documentation for selecting the 1.5 (50%) retrofit factor over the other factors discussed above in the CCM or to select a different factor as appropriate according to the CCM.

1. Relevant to the Regional Haze 2nd Implementation Planning Period, the value of retrofit factors used should be supported and documented in the control cost analysis.
2. The basis for a consistent approach to retrofit factors can be found in the CCM and specific chapters in the CCM on control devices as appropriate. A broad discussion of how to estimate retrofit factors can be found in the Cost Estimation Chapter in the CCM (Section 1, Chapter 2, 7th Edition). There is also discussion on estimating retrofit factors specific to each control device in each relevant chapter in the CCM.
3. There are specific types of data that should be evaluated to justify a retrofit factor as discussed in the CCM. The CCM goes on to explain that no general factors can be developed since each retrofit is unique, and that estimation of retrofit factors can be "as much art as it is science." However, consideration of the following types of information could be used in developing retrofit costs: (1) Handling and Erection, (2) Site Preparation, (3) Off-Site Facilities, (4) Limited Space for Staging Equipment, (5) Transportation, and (6) Lost Production.
4. See CCM (7th Edition), Section 1, Chapter 2, Cost Estimation: Concepts and Methodology, Section 2.6.4.2, pages 27 to 29, https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.

a. From the general comments -- Interest Rate

i. USEPA’s Control Cost Manual (CCM) recommends using a firm specific interest rate or the bank prime rate if no information specific to the parent firm is available. The current prime rate is 3.25%. Any other rates should be justified. Consideration of the cost of equity for a parent company as well as its cost of debt would be appropriate for a firm to justify a rate used in the context of a four-factor analysis. See CCM (7th Edition) Section 1, Chapter 2, Cost Estimation: Concepts and Methodology, https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

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Our mission is to protect and improve the environment and human health.

Southern Minnesota Beet Sugar Cooperative
83550 County Road 21, Renville, Minnesota 56284

September 14, 2021

Hassan Bouchareb
Minnesota Pollution Control Agency
520 Lafayette Road N
St. Paul, MN 55155

Re: Follow-Up Response to MPCA/EPA/FLM Four Factor Analysis Comments on SO_2 Control Costs

Dear Mr. Bouchareb:

Southern Minnesota Beet Sugar Cooperative (SMBSC) submitted a Regional Haze Four-Factor Analysis (FFA) on July 31, 2020 for Boiler No. 1 (Boiler 1, EQUI 17). SMBSC received an email from the MPCA on June 8, 2021, which provided comments on SMBSC's FFA. Comments were provided by the MPCA, the U.S. Environmental Protection Agency (EPA), and the Federal Land Managers (FLMs). SMBSC provided an initial response to the comments on July 23, 2021. However, some comments required additional information that required more time to gather in order to adequately respond. SMBSC committed to providing the remaining requested information by August 23, 2021 for the SO_2 control cost estimates. On August 23, 2021 SMBSC requested an extension until September 10, 2021 to receive remaining information from vendors. SMBSC requested an additional extension until September 17, 2021 to compile and submit the updated response.

This letter provides the information to supplement the July 23, 2021 memorandum. The bold heading below summarizes the essence of the applicable comment. The detailed comment email from MPCA is included in Attachment A for reference.

Revise the SO_2 Control Cost Analysis Based on Information Specific to SMBSC[1]

The MPCA and FLMs stated that SMBSC should base control costs off site-specific vendor quotes or cost models such as the updated CCM. SMBSC initially calculated the costs for spray dry absorbers (SDAs) and dry sorbent injection (DSI) by scaling historical cost estimates to present day using Chemical Engineering Plant Cost Index (CEPCI) and the six tenths power law to account for capacity differences. The MPCA and FLMs requested SMBSC to provide a site-specific cost estimates or use recent cost models such as the updated CCM. Inflationary indices (CEPCI) and capacity scaling factors (six tenths power law)[2] used to adjust historical costs to present day and account for capacity differences are commonly practiced by engineers and

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[1] MPCA Comment 1, FLM Comment 4a (Attachment A)

[2] Turton, Richard; et al. 2008. *Analysis, Synthesis, and Design of Chemical Processes* 3rd ed). Pearson College Div; page 183.

should be considered reliable. For example, CEPCI is extensively used by the EPA.[3] The Lake Michigan Air Directors Consortium (LADCO) used inflationary estimates in the *Four-Factor Analysis for Regional Haze in the Northern Midwest Class I Areas* to adjust costs exceeding five years beyond the study year.[4] SMBSC is aware that more recent site-specific quotes may represent the most accurate representation of equipment costs from the current year, but the use of CEPCI is not an unreasonable means to adjust costs to present day in the absence of a current vendor quotation.

Nonetheless, SMBSC has obtained vendor estimates specific to the flue gas characteristics of the facility. Table 1 provides the updated control cost estimates based on the vendor quotes obtained since the FFA comments were received. An updated control cost spreadsheet is provided in Attachment B.

Table 1 - SO_2 Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton
Spray Dry Absorber (SDA) with Baghouse (including lime slaking system)	90%	78.6	707.2	$54,500,000	$8,040,000	$11,400
Dry Sorbent Injection (DSI) with Baghouse (including trona injection system)	70%	235.7	550.0	$37,800,000	$7,080,000	$12,800

These costs are significantly higher than what is considered to be cost effective. Therefore, SDAs and DSI are eliminated from further consideration.

We appreciate your efforts to review the SMBSC FFA. Should you have any questions or comments regarding this submittal, please contact me by telephone at 320-329-4174 or via email at sagar@smbsc.com.

Sincerely,

Sagar Sunkavalli
Manager of Environmental Affairs

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[3] EPA, Control Cost Manual, 7th Edition

[4] Amec Foster Wheeler Environment & Infrastructure, Inc. (2015, October 27). Four-Factor Analysis for Regional Haze in the Northern Midwest Class I Areas: Methodology for Source Selection, Evaluation of Control Options, and Four Factor Analysis.

Attachment A

Regional Haze: Four Factor Analysis Review/Questions: Southern Minnesota Beet Sugar Cooperative Email

From: Bouchareb, Hassan (MPCA) <hassan.bouchareb@state.mn.us>
Sent: Tuesday, June 8, 2021 10:58 AM
To: Vidyasagar Sunkavalli <Vidyasagar.Sunkavalli@smbsc.com>
Cc: deAlwis, Deepa (MPCA) <deepa.dealwis@state.mn.us>
Subject: Regional Haze :: Four Factor Analysis Review/Questions :: Southern MN Beet Sugar

Good morning Sagar,

Thanks for your patience so far regarding regional haze related efforts. I have reviewed the four factor analyses prepared for Southern Minnesota Beet Sugar Coop and have a few comments. I also wanted to forward comments on the analyses that I received from EPA and the federal land managers (FLMs) from the Forest Service and National Parks Service that I would like to address as well. I've tried to summarize the various requests based on MPCA's review and the comments/requests received from EPA and the FLMs to group them by general area. More detail on these requests is available farther down.

I would like further discuss these comments with you and your team if you have the time available. My intention is to give you a general update on where things are at with respect to the Regional Haze SIP, what is going into the decision-making process for this project, and a brief update on the tentative schedule for preparing and submitting this SIP to EPA for approval.

I'm not sure who all you would like to be at this discussion, but if you let me know a few dates/times that work for your team I'd be happy to make those times work. If you can get back to me within a week (by June 15th) that would be great.

Thanks in advance!

Request Summary:

1. SO_2 controls
    a. Address comments related to cost analysis methodology (MPCA comment 1, FLM comment 4)
2. NO_X controls
    a. Address comments related to cost analysis methodology (MPCA comment 3, FLM comment 2/3)
3. Retrofit Factor
    a. Please provide additional information regarding the choice of retrofit factor and how you arrived at that value (MPCA comment 2a, FLM comment 2a/3a/4b, EPA comment 4a)
4. Interest Rate
    a. Revise control cost estimates to use the current prime interest rate (3.25%) per the control cost manual suggested default or provide supporting documentation to support the 5.5% interest rate used in the current analyses (FLM comment 2d/3c/4f, EPA comment 3b).

Specific Comments (MPCA):

MPCA has the following questions/comments.

1. SO_2 controls
    a. Please revise the SO_2 controls analysis to base capital costs on information specific to Southern Minnesota Beet Sugar instead of the cost estimates from Northshore Mining's 2006 BART analysis

i. Note that there is a SO_2 control cost spreadsheet that is now available from EPA to estimate costs of various SO_2 controls

ii. I suggest that you update the cost estimates to use these spreadsheet now that it is available (first released in May 2021)

2. Retrofit factor
    a. For the analyses, a retrofit factor of 1.5 (50%) is used for cost estimates. The value of retrofit factors used should be supported and documented in the control cost analysis.
    b. Note -- EPA's Control Cost Manual offers some guidance on selecting retrofit factors for various control technologies:

i. SNCR - "A retrofit factor of 0.84 should be used for new construction and a retrofit factor of 1 should be used for SNCR retrofits to existing boilers, where the retrofit is of an average level of difficulty." CCM (7th Edition), Section 4, Chapter 1, page 1-42..

ii. SCR - "A retrofit factor of 0.8 should be used for new construction and a retrofit factor of 1 should be used for average retrofits. … For retrofits that are more complicated than average, a retrofit factor of greater than 1 can be used to estimate capital costs provided the reasons for using a higher retrofit factor are appropriate and fully documented." CCM (7th Edition), Section 4, Chapter 2, page 66 of 107.

iii. SDA/DSI - "A retrofit factor (RF) of 0.77 should be used for new construction and a retrofit factor of 1 should be used for retrofits to existing units, where the retrofit is of an average level of difficulty." CCM (7th Edition), Section 5, Chapter 1, page 1-48.

3. NO_X controls
    a. Regarding the FLM comments focusing on costs for various components (e.g., catalyst life, reagent cost, water cost, etc.), I believe most of the changes noted are due to upscaling costs to 2020 dollars. If not, please provide additional clarification on how you arrived at the values used

Specific Comments (Federal Land Managers - FLMs)

As part of the regional haze program, Federal Land Managers have a more direct role in the development of states' regional haze SIPs. Part of this includes consultation prior to the public notice period of the SIP. MPCA provided the FLMs with the a link to the webpage where the four factor analyses are posted and offered the ability to provide comments and questions on the analyses. Specific comments to the analyses prepared are below:

1. Baseline Emissions:
    a. 2017 NEI SO2 and NOx emissions are greater than 2016 and assumed for 2028.
2. SCR Analysis:
    a. The 1.5 retrofit factor is not justified. Site-specific retrofit factors should be based upon a thorough and well-documented analysis of the individual factors involved in a project. For example, the methods outlined by William Vatavuk on pages 59-62 in his book Estimating Costs of Air Pollution Control be followed. That process involves estimating and assigning a retrofit factor to each major element of a project and from that deriving an overall retrofit factor. The CCM also addresses "Retrofit Cost Considerations" in section 2.6.4.2. In the absence of such a proper analysis, assume a retrofit factor = 1.0, which represents a 30% increase above costs for a "greenfield" project.
    b. Inlet NOx is slightly underestimated.
    c. Catalyst life and SCR life are underestimated relative to the CCM defaults with no justification.
    d. Interest rate should be the current bank prime rate = 3.25% instead of 5.5%.
    e. Reagent cost, water cost, electricity cost, catalyst cost and labor cost all appear to have been inflated from default values with no justification; actual values should be used.
    f. Barr has over-ridden the CCM calculated values for "Total operating time for the SNCR (top)" and "Total NOx removed per year " to reflect actual hours of operation and expected emission reductions. While this is OK, it should have been noted and explained. Instead of altering the internal workings of the workbook, Barr should have adjusted the data inputs to reflect the anticipated emission reductions.
    g. Why is reheat needed for SCR? Can SCR be installed ahead of the air preheater, or some location with suitable temperature?

3. SNCR Analysis:
    a. The 1.5 retrofit factor is not justified (see above).
    b. How was removal efficiency/outlet NOx rate determined?
    c. Interest rate should be the current bank prime rate = 3.25% instead of 5.5%.
    d. Reagent cost, water cost, electricity cost, fuel cost, and ash disposal cost all appear to have been inflated from default values with no justification.
    e. Barr has over-ridden the CCM calculated values for "Total operating time for the SNCR (top)" and "Total NOx removed per year " to reflect actual hours of operation and expected emission reductions. While this is OK, it should have been noted and explained. Instead of altering the internal workings of the workbook, Barr should have adjusted the data inputs to reflect the anticipated emission reductions.
4. SO_2 Controls:
    a. The SO_2 control cost estimates are based upon the Northshore Mining Powerhouse #2 2006 BART submittal and were scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI).

i. According to section 2.5.3 of the CCM: **2.5.3 Prices and Inflation** -- It should be noted that the accuracy associated with escalation (and its reverse, de- escalation) declines the longer the time period over which this is done. Escalation with a time horizon of more than five years is typically not considered appropriate as such escalation does not yield a reasonably accurate estimate. Thus, obtaining new price quotes for cost items is advisable beyond five years. If longer escalation periods are unavoidable due to limited recent cost data that is reasonably available, then the analysis should use the principles in this Manual chapter to provide as accurate an escalation as possible consistent with the Manual given the limitations of the cost analysis. The appropriate length of time for escalation can vary as a result of significant changes in the cost of major production inputs(e.g., energy, steel, chemical reagents, etc.) and technological changes in control measures, particularly if these changes occur in an unusually short period of time. Hence, shorter time periods for escalation and de-escalation are clearly preferred over longer ones.

ii. Instead of using an obsolete vendor quote from a different facility, SMBSC/Barr should provide a new cost estimate using either a current vendor quote for this facility or apply current costing models for DSI, Spray Dry Absorbers, and Wet FGD. (Why was wet FGD omitted from the Barr analysis?) We recommend use of the proposed revision to the SO2 and Acid Gas Control chapter in the CCM or the IPM models (developed by Sargent & Lundy) upon which the proposed CCM revisions are based.

    b. The 1.5 retrofit factor is not justified.
    c. SO2 control efficiencies were underestimated.
    d. Taxes were included. (Does MN levy sales and property taxes on APC equipment?)
    e. Equipment life was underestimated.
    f. Interest rate should be the current bank prime rate = 3.25% instead of 5.5%.

Specific Comments (EPA):

MPCA also provided EPA with the link to the four factor analyses. EPA also provided comments on the collection of four factor analyses prepared. Specific comments to the analyses prepared are below:

1. For Southern Minnesota Beet Coop, Barr evaluated Boiler No. 1 for NOx and SO2 controls and provided a review of the visibility impacts. The four-factor analysis looked at NOx controls (SCR, SNCR, LNB, LNB+OFA) and SO2 controls (SDA, DSI). For NOx, Barr found that the cost effectiveness of reductions ($3600 - $7000/ton) exceeded cost effectiveness stated in EPA's Final TSD for CSAPR, and Barr concluded that none of the evaluated NOx controls were reasonable. For SO2, Barr found that the cost effectiveness of reductions ($12,7000 – $16,600/ton) exceeded cost effectiveness from MPCA's original BART and concluded that none of the SO2 controls were reasonable.
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3. Please see the General Comments above regarding interest rates and retrofit factors for the analysis pertaining to Boiler No. 1.
    a. From the general comments -- Retrofit Factors

i. For example -- For the analyses, a retrofit factor of 1.5 (50%) is used. The value of retrofit factors used should be supported and documented in the control cost analysis. EPA's Control Cost Manual states, "A retrofit factor of 0.84 should be used for new construction and a retrofit factor of 1 should be used for SNCR retrofits to existing boilers, where the retrofit is of an average level of difficulty." CCM (7th Edition), Section 4.2, Chapter 1, page 1-42. It would be helpful to provide support and documentation for selecting the 1.5 (50%) retrofit factor over the other factors discussed above in the CCM or to select a different factor as appropriate according to the CCM.

1. Relevant to the Regional Haze 2nd Implementation Planning Period, the value of retrofit factors used should be supported and documented in the control cost analysis.
2. The basis for a consistent approach to retrofit factors can be found in the CCM and specific chapters in the CCM on control devices as appropriate. A broad discussion of how to estimate retrofit factors can be found in the Cost Estimation Chapter in the CCM (Section 1, Chapter 2, 7th Edition). There is also discussion on estimating retrofit factors specific to each control device in each relevant chapter in the CCM.
3. There are specific types of data that should be evaluated to justify a retrofit factor as discussed in the CCM. The CCM goes on to explain that no general factors can be developed since each retrofit is unique, and that estimation of retrofit factors can be "as much art as it is science." However, consideration of the following types of information could be used in developing retrofit costs: (1) Handling and Erection, (2) Site Preparation, (3) Off-Site Facilities, (4) Limited Space for Staging Equipment, (5) Transportation, and (6) Lost Production.
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a. From the general comments -- Interest Rate

  i. USEPA’s Control Cost Manual (CCM) recommends using a firm specific interest rate or the bank prime rate if no information specific to the parent firm is available. The current prime rate is 3.25%. Any other rates should be justified. Consideration of the cost of equity for a parent company as well as its cost of debt would be appropriate for a firm to justify a rate used in the context of a four-factor analysis. See CCM (7th Edition) Section 1, Chapter 2, Cost Estimation: Concepts and Methodology, https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

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Our mission is to protect and improve the environment and human health.

Attachment B

Updated SO_2 Control Costs

Southern Minnesota Beet Sugar Coop (SMBSC)
Attachment B - Updated SO2 Control Costs
Table 1: Cost Summary

SO_2 Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton
Spray Dry Absorber (SDA) with Baghouse (including lime slaking system)	90%	78.6	707.2	$54,520,933	$8,035,215	$11,362
Dry Sorbent Injection (DSI) with Baghouse (including trona injection system)	70%	235.7	550.0	$37,755,277	$7,040,200	$12,800

Southern Minnesota Beet Sugar Coop (SMBSC)
Attachment B - Updated SO2 Control Costs
Table 2: Summary of Utility, Chemical and Supply Costs

Operating Unit:	Boiler 1	**Study Year**	2021
Emission Unit Number	EQUI17		
Stack/Vent Number	STRU25		

Item	2021 Unit Cost	Units	Cost	Year	Data Source	Notes
Operating Labor	70	$/hr	60	2016	EPA SCR Control Cost Manual Spreadsheet	
Maintenance Labor	70	$/hr				Assumed to be equivalent to operating labor
Installation Labor	70	$/hr				Assumed to be equivalent to operating labor
Electricity	0.08	$/kwh			2015-2019 EIA Average prices for the commerical sector	
Natural Gas	3.90	$/kscf			2015-2019 EIA Average prices for the commerical sector	
Water	5.28	$/mgal	4.17	2013	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Compressed Air	0.50	$/kscf	0.38	2012	Taconite FIP Docket	
Chemicals & Supplies						
Lime	189.19	$/ton	145.00	2012	Taconite FIP Docket	
Trona	285.00	$/ton		2020	Reagent cost for trona from another Barr Engineering Co. Project.	
Fabric Filter Bags	234.86	$/bag	180	2012	Taconite FIP Docket	
Other						
Sales Tax	6.875%				Minnesota sales tax rate	
Interest Rate	5.50%			2016	EPA SCR Control Cost Manual Spreadsheet	
Solid Waste Disposal	65.24	$/ton	50	2012	Taconite FIP Docket	
Contingencies	10%	of purchased equip cost (B)			EPA Cost Control Cost Manual Chapter 2	Suggested contingency range of 5% to 15% of total capital investment
Markup on capital investment (retrofit factor)	50%				EPA Cost Control Cost Manual Chapter 2	
Operating Information						
Annual Op. Hrs	7,536	Hours			Average of 2015-2019 Operating Data	
Utilization Rate	100%				Assumed	
Design Capacity	472.4	MMBTU/hr			Boiler Design Capacity	
Equipment Life	20	yrs			Assumed	
Temperature	370	Deg F			SMBSC CEMS Stack Temperature Data	2018-2020 Average, excluding periods of boiler shutdown/startup
Moisture Content	11.8%				2014 Boiler 1 Hg Stack Test Data	
Actual Flow Rate	209,000	acfm			2014 Boiler 1 Hg Stack Test Data	
Standardized Flow Rate	132,954	scfm @ 68º F	123,889	scfm @ 32º F	Calculated Value	
Dry Std Flow Rate	117,332	dscfm @ 68º F			Calculated Value	
Fuel higher heating value (HHV)	9,152	BTU/lb			SMBSC Site Specific Data	Average of 2015-2019 Operating Data
Plant Elevation	1,100	Feet above sea level				Renville, MN elevation
Sulfur Content (%)	0.28	%			SMBSC Site Specific Data	Average of 2015-2019 Operating Data
# days boiler operates	314	days			SMBSC Site Specific Data	Average of 2015-2019 Operating Data
	Baseline Emissions		**lb/hr**	**ton/year**		
Pollutant	**Lb/Hr**	**Ton/Year**	**ppmv**	**ppmv**	**lb/mmbtu**	
Sulfur Dioxides (SO2)	208.5	785.8	178	178.0		Baseline ton/year is based on 2028 SO2 modeling emission inventory.
SDA - SO_2 Control Efficiency	90%				EPA fact sheet for flue gas desulfurization (new installations) https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf	
DSI - SO_2 Control Efficiency	70%	Trona Ore Control Efficiency			Control efficiency is based on trona as injected reagent.	

Southern Minnesota Beet Sugar Coop (SMBSC)
Attachment B - Updated SO2 Control Costs
Table 3: SO2 Control Spray Dry Absorber (SDA) with Baghouse (including lime system)

Operating Unit: **Boiler 1**

Emission Unit Number	EQUI17		Stack/Vent Number	STRU25	
Design Capacity	472	MMBtu/hr	Standardized Flow Rate	123,889	scfm @ 32º F
Utilization Rate	100%		Temperature	370	Deg F
Annual Operating Hours	7,536	Hours	Moisture Content	11.8%	
Annual Interest Rate	5.5%		Actual Flow Rate	209,000	acfm
Equipment Life	20	yrs	Standardized Flow Rate	132,954	scfm @ 68º F
			Dry Std Flow Rate	117,332	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								**13,364,399**
Purchased Equipment Total (B)	22%	of control device cost (A)						**16,287,862**
Installation - Standard Costs	74%	of purchased equip cost (B)						12,053,018
Installation - Site Specific Costs								NA
Installation Total								12,053,018
Total Direct Capital Cost, DC								28,340,879
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)						8,469,688
Total Capital Investment (TCI) = DC + IC								**36,810,567**
Adjusted TCI for Replacment Parts								**36,347,288**
TCI with Retrofit Factor								**54,520,933**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						1,014,566
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						7,020,649
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**8,035,215**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc.**	**Conc. Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10						0.0	-	NA
PM2.5						0.0	-	NA
Total Particulates						0.0	-	NA
Nitrous Oxides (NOx)						0.0	-	NA
Sulfur Dioxide (SO_2)		785.8	90%			78.6	707.2	11,362
Sulfuric Acid Mist						0.00	-	NA
Fluorides						0.0	-	NA
Volatile Organic Compounds (VOC)						0.0	-	NA
Carbon Monoxide (CO)						0.0	-	NA
Lead (Pb)						0.00	-	NA

Notes & Assumptions

1 SDA capital costs provided by vendor. Capital cost includes new anciliary equipment.
2 Ancillary equipment costs scaled up to design airflow using the 6/10 power law
3 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

Southern Minnesota Beet Sugar Coop (SMBSC)
Attachment B - Updated SO2 Control Costs
Table 3: SO2 Control Spray Dry Absorber (SDA) with Baghouse (including lime system)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) [(1)]			**13,364,399**
Purchased Equipment Costs (A) - Absorber + packing + auxiliary equipment, EC			
Instrumentation	10%	of control device cost (A)	1,336,440
State Sales Taxes	6.9%	of control device cost (A)	918,802
Freight	5%	of control device cost (A)	668,220
Purchased Equipment Total (B)	22%		**16,287,862**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	651,514
Handling & erection	50%	of purchased equip cost (B)	8,143,931
Electrical	8%	of purchased equip cost (B)	1,303,029
Piping	1%	of purchased equip cost (B)	162,879
Insulation	7%	of purchased equip cost (B)	1,140,150
Painting	4%	of purchased equip cost (B)	651,514
Installation Subtotal Standard Expenses	74%		**12,053,018**
Other Specific Costs (see summary)			
Site Preparation, as required	N/A	Site Specific	-
Buildings, as required	N/A	Site Specific	-
Site Specific - Other	N/A	Site Specific	-
Total Site Specific Costs			NA
Installation Total			**12,053,018**
Total Direct Capital Cost, DC			**28,340,879**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	1,628,786
Construction & field expenses	20%	of purchased equip cost (B)	3,257,572
Contractor fees	10%	of purchased equip cost (B)	1,628,786
Start-up	1%	of purchased equip cost (B)	162,879
Performance test	1%	of purchased equip cost (B)	162,879
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	1,628,786
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**8,469,688**
Total Capital Investment (TCI) = DC + IC			**36,810,567**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**36,347,288**
Total Capital Investment (TCI) with Retrofit Factor	50%		**54,520,933**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	69.56	$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr	131,044
Supervisor	15%	15% of Operator Costs	19,657
Maintenance			
Maintenance Labor	69.56	$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr	65,522
Maintenance Materials	100%	of maintenance labor costs	65,522
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.08	$/kwh, 378.3 kW-hr, 7536 hr/yr, 100% utilization	226,923
Compressed Air	0.50	$/kscf, 2.0 scfm/kacfm, 7536 hr/yr, 100% utilization	93,710
N/A			-
SW Disposal	65.24	$/ton, 0.2 ton/hr, 7536 hr/yr, 100% utilization	102,545
Lime	189.19	$/ton, 282.2 lb/hr, 7536 hr/yr, 100% utilization	201,154
Filter Bags	234.86	$/bag, 1,620 bags, 7536 hr/yr, 100% utilization	108,489
N/A			
N/A			-
N/A			-
N/A			-
N/A			-
N/A			-
N/A			-
N/A			-
Total Annual Direct Operating Costs			**1,014,566**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	169,047
Administration (2% total capital costs)	2%	of total capital costs (TCI)	1,090,419
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	545,209
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	545,209
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	4,670,764
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**7,020,649**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**8,035,215**

Southern Minnesota Beet Sugar Coop (SMBSC)
Attachment B - Updated SO2 Control Costs
Table 3: SO2 Control Spray Dry Absorber (SDA) with Baghouse (including lime system)

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:	**Filter Bags**	
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	234.86	$/bag
Amount Required	1620	
Total Rep Parts Cost	425,718	Cost adjusted for freight & sales tax
Installation Labor	37,560	20 min per bag
Total Installed Cost	**463,279**	**Zero out if no replacement parts needed**
Annualized Cost	**108,489**	

Electrical Use

	Flow acfm	D P in H2O	Efficiency	Hp	kW
Blower, Baghouse	209,000	10.00			2,850,793
Total					2,850,793

Reagents and Other Operating Costs

Lime Use Rate	1.30	lb-mole CaO/lb-mole SO2	282.17	lb/hr Lime
Solid Waste Disposal	1,572	ton/yr SDA unreacted sorbent and reaction byproducts		

Operating Cost Calculations

Utilization Rate	100%	Annual Operating Hours	7,536

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	69.56	$/Hr	2.0	hr/8 hr shift	1,884	$ 131,044	$/Hr, 2.0 hr/8 hr shift, 7536 hr/yr
Supervisor	15%	of Op.			NA	$ 19,657	15% of Operator Costs
Maintenance							
Maint Labor	69.56	$/Hr	1.0	hr/8 hr shift	942	$ 65,522	$/Hr, 1.0 hr/8 hr shift, 7536 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	$ 65,522	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.080	$/kwh	378.3	kW-hr	2,850,793	$ 226,923	$/kwh, 378.3 kW-hr, 7536 hr/yr, 100% utilization
Compressed Air	0.496	$/kscf	2	scfm/kacfm	189,003	$ 93,710	$/kscf, 2.0 scfm/kacfm, 7536 hr/yr, 100% utilization
Water	5.282	$/mgal		gpm			$/mgal, 0 gpm, 7536 hr/yr, 100% utilization
SW Disposal	65.24	$/ton	0.21	ton/hr	1,572	$ 102,545	$/ton, 0.2 ton/hr, 7536 hr/yr, 100% utilization
Lime	189.19	$/ton	282.2	lb/hr	1,063	$ 201,154	$/ton, 282.2 lb/hr, 7536 hr/yr, 100% utilization
Filter Bags	234.86	$/bag	1,620	bags	N/A	$ 108,489	$/bag, 1,620 bags, 7536 hr/yr, 100% utilization

Southern Minnesota Beet Sugar Coop (SMBSC)
Attachment B - Updated SO2 Control Costs
Table 4: SO2 Control Dry Sorbent Injection (DSI) with Baghouse (including injection system)

Operating Unit: **Boiler 1**

Emission Unit Number			Stack/Vent Number		
Design Capacity	472	MMBtu/hr	Standardized Flow Rate	123,889	scfm @ 32º F
Utilization Rate	100%		Exhaust Temperature	370	Deg F
Annual Operating Hours	7,536	hr/yr	Exhaust Moisture Content	11.8%	
Annual Interest Rate	5.50%		Actual Flow Rate	209,000	acfm
Control Equipment Life	20	yrs	Standardized Flow Rate	132,954	scfm @ 68º F
Plant Elevation	1100	ft	Dry Std Flow Rate	117,332	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs						
Direct Capital Costs						
Purchased Equipment (A)						**9,306,454**
Purchased Equipment Total (B)	22%	of control device cost (A)				**11,342,240**
Installation - Standard Costs	74%	of purchased equip cost (B)				8,393,258
Installation - Site Specific Costs						N/A
Installation Total						8,393,258
Total Direct Capital Cost, DC						19,735,498
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)				5,897,965
Total Capital Investment (TCI) = DC + IC						**25,170,185**
Adjusted TCI for Replacement Parts						25,170,185
Total Capital Investment (TCI) with Retrofit Factor						**37,755,277**
Operating Costs						
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.				2,093,116
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost				4,947,084
Total Annual Cost (Annualized Capital Cost + Operating Cost)						**7,040,200**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual Ton/Yr**	**Cont Eff %**	**Cont Emis Ton/Yr**	**Reduction Ton/Yr**	**Cont Cost $/Ton Rem**
PM10						
PM2.5						
Total Particulates						
Nitrous Oxides (NOx)						
Sulfur Dioxide (SO2)	208.54	785.76	70%	235.73	550.03	$12,800
Sulfuric Acid Mist (H2SO4)						
Fluorides						
Volatile Organic Compounds (VOC)						
Carbon Monoxide (CO)						
Lead (Pb)						

Notes & Assumptions

1. DSI capital costs provided by vendor. Capital cost includes new anciliary equipment.
2. Ancillary Costs scaled up to design airflow using the 6/10 power law
3. Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

Southern Minnesota Beet Sugar Coop (SMBSC)
Attachment B - Updated SO2 Control Costs
Table 4: SO2 Control Dry Sorbent Injection (DSI) with Baghouse (including injection system)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**9,306,454**
Purchased Equipment Costs (A) - Injection System + auxiliary equipment, EC			
Instrumentation	10%	Included in vendor estimate	930,645
State Sales Taxes	6.9%	of control device cost (A)	639,819
Freight	5%	of control device cost (A)	465,323
Purchased Equipment Total (B)	22%		**11,342,240**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	453,690
Handling & erection	50%	of purchased equip cost (B)	5,671,120
Electrical	8%	of purchased equip cost (B)	907,379
Piping	1%	of purchased equip cost (B)	113,422
Insulation	7%	of purchased equip cost (B)	793,957
Painting	4%	Included in vendor estimate	453,690
Installation Subtotal Standard Expenses	74%		**8,393,258**
Other Specific Costs (see summary)			
Site Preparation, as required	N/A	Site Specific	
Buildings, as required	N/A	Site Specific	
Lost Production for Tie-In	N/A	Site Specific	
Total Site Specific Costs			N/A
Installation Total			**8,393,258**
Total Direct Capital Cost, DC			**19,735,498**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	1,134,224
Construction & field expenses	20%	of purchased equip cost (B)	2,268,448
Contractor fees	10%	of purchased equip cost (B)	1,134,224
Start-up	1%	of purchased equip cost (B)	113,422
Performance test	1%	of purchased equip cost (B)	113,422
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	1,134,224
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**5,897,965**
Total Capital Investment (TCI) = DC + IC			**25,633,463**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**25,170,185**
Total Capital Investment (TCI) with Retrofit Factor	50%		**37,755,277**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	69.56	$/Hr	131,044
Supervisor	0.15	of Op Labor	19,657
Maintenance			
Maintenance Labor	69.56	$/Hr	65,522
Maintenance Materials	100	% of Maintenance Labor	65,522
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.08	$/kwh, 227.0 kW-hr, 7536 hr/yr, 100% utilization	136,154
N/A			-
Compressed Air	0.50	$/kscf, 2.0 scfm/kacfm, 7536 hr/yr, 100% utilization	93,710
N/A			-
Solid Waste Disposal	65.24	$/ton, 0.5 ton/hr, 7536 hr/yr, 100% utilization	228,801
Trona	285.00	$/ton, 1,158.6 lb/hr, 7536 hr/yr, 100% utilization	1,244,217
Filter Bags	234.86	$/bag, 1,620 bags, 7536 hr/yr, 100% utilization	108,489
N/A			-
N/A			-
N/A			-
N/A			-
Total Annual Direct Operating Costs			**2,093,116**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	169,047
Administration (2% total capital costs)	2%	of total capital costs (TCI)	755,106
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	377,553
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	377,553
Capital Recovery	0.0837	for a 20-year equipment life and a 5.5% interest rate	3,159,336
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery costs	**4,947,084**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**7,040,200**

Southern Minnesota Beet Sugar Coop (SMBSC)
Attachment B - Updated SO2 Control Costs
Table 4: SO2 Control Dry Sorbent Injection (DSI) with Baghouse (including injection system)

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment: **Filter Bags**

Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	234.86	$/bag
Amount Required	1620	Bags
Total Rep Parts Cost	425,718	Cost adjusted for freight, sales tax, and bag disposal
Installation Labor	37,560	20 min per bag
Total Installed Cost	**463,279**	
Annualized Cost	**108,489**	

Electrical Use

	Flow acfm	D P in H2O	kWhr/yr
Blower	209,000	6.00	1,710,476
Total			1,710,476

Reagent Use & Other Operating Costs

Trona use - 1.5 NSR	208.54	lb/hr SO2	1158.62	lb/hr Trona
Solid Waste Disposal	3,507	ton/yr DSI unreacted sorbent and reaction byproducts		

Operating Cost Calculations

Utilization Rate	100%	Annual Operating Hours	7,536

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	69.56	$/Hr	2.0	hr/8 hr shift	1,884	$ 131,044	$/Hr, 2.0 hr/8 hr shift, 1,884 hr/yr
Supervisor	15%	of Op Labor			NA	$ 19,657	% of Operator Costs
Maintenance							
Maint Labor	69.56	$/Hr	1.0	hr/8 hr shift	942	$ 65,522	$/Hr, 1.0 hr/8 hr shift, 942 hr/yr
Maint Mtls	100%	of Maintenance Labor			NA	$ 65,522	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.080	$/kwh	227.0	kW-hr	1,710,476	$ 136,154	$/kwh, 227.0 kW-hr, 7536 hr/yr, 100% utilization
Water			N/A	gpm			
Compressed Air	0.496	$/kscf	2.0	scfm/kacfm	189,003	$ 93,710	$/kscf, 2.0 scfm/kacfm, 7536 hr/yr, 100% utilization
Cooling Water			N/A	gpm			
Solid Waste Disposal	65.24	$/ton	0.5	ton/hr	3,507	$ 228,801	$/ton, 0.5 ton/hr, 7536 hr/yr, 100% utilization
Trona	285.00	$/ton	1,158.6	lb/hr	4,366	$ 1,244,217	$/ton, 1,158.6 lb/hr, 7536 hr/yr, 100% utilization
Filter Bags	234.86	$/bag	1,620	bags	N/A	$ 108,489	$/bag, 1,620 bags, 7536 hr/yr, 100% utilization

Southern Minnesota Beet Sugar Cooperative
83550 County Road 21, Renville, Minnesota 56284

March 14, 2022

Hassan Bouchareb
Minnesota Pollution Control Agency
520 Lafayette Road N
St. Paul, MN 55155

Re: Response to MPCA Request to Install Selective Non-Catalytic Reduction (SNCR)

Dear Mr. Bouchareb:

Southern Minnesota Beet Sugar Cooperative (SMBSC) is submitting this letter and its supporting information in response to recent meetings SMBSC has had with the Minnesota Pollution Control Agency (MPCA). As you are aware, SMBSC submitted a Regional Haze Four-Factor Analysis (FFA) on July 31, 2020 for Boiler No. 1 (Boiler 1, EQUI 17). On January 18th, 2022, the Minnesota Pollution Control Agency (MPCA) met with SMBSC to inform decisions for the second Regional Haze State Implementation Plan (SIP) regarding what emission reductions are necessary to make reasonable progress. During the meeting, MPCA informed SMBSC that they are recommending the installation of SNCR on Boiler 1 as MPCA has determined SNCR is cost effective. SMBSC and MPCA met again on February 14th, 2022 where SMBSC stated its disagreement with MPCA's recommendation. Although SMBSC responded to MPCA's initial request in 2020[1] with a complete FFA, SMBSC does not believe additional controls are cost effective when all considerations are taken into account, not just the cost per pollutant reduced. SMBSC appreciates the opportunity to discuss this topic with MPCA and provide this additional information. The following key points are the basis for why SMBSC disagrees with MPCA's recommendation and should not have to install additional controls for the SIP.

1 Q/d Screening Considerations

For the second regional haze planning period, States have focused on demonstrating there is reasonable progress being made towards natural visibility goals, and if additional efforts are warranted, used the FFA methodology as outlined by the U.S. Environmental Protection Agency to select sources for additional emission reductions. At the outset, SMBSC should not have been selected by MPCA to conduct a FFA and thus evaluate potential control measures. MPCA applied an aggressive technique in selecting sources for further analysis by ranking sources by their Q/d (a source's annual emissions in tons divided by the distance in kilometers between the source and the nearest Class I area) and requiring further evaluation for sources with a Q/D > 4, and in some situations less than 4 (which is the case with SMBSC). In particular, MPCA essentially indicated during the February 14, 2022 meeting that the reason MPCA deployed a Q/d of less than 4 to SMBSC was to specifically ensure that SMBSC was pulled into the FFA analysis, out of a desire to further regulate SMBSC's coal-fired boiler. MPCA thus reverse-

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[1] February 14, 2020 letter from Hassan Bouchareb of MPCA to Derwood Brady of Southern Minnesota Beet Sugar Cooperative

engineered the Q/d to produce a pre-determined FFA result. This is both scientifically and legally problematic.

As described in the guidance[2] on regional haze state implementation plans for the second implementation period, States may find some or all of the following techniques useful for examining source impacts for the second implementation period:

a. Emissions divided by distance (Q/d)

b. Trajectory analyses

c. Residence time analyses

d. Photochemical modeling (zero-out and/or source apportionment)

The above techniques are listed in order from the least complicated (Q/d) to the most complicated and resource intensive (photochemical modeling). Each technique has advantages and disadvantages. In general, the simple techniques (Q/d) are easy to implement, but do not provide detailed information. The more sophisticated techniques provide detailed information on particulate matter (PM) and PM species impacts. States may use Q/d as a surrogate for source visibility impacts, along with a ***reasonably*** selected threshold for this metric. Q/d is a less reliable indicator of actual visibility impact because it does not consider transport directions and pathways, dispersion and photochemical processes, or the particular days that have the most anthropogenic impairment due to all sources. MPCA selected the easiest and least accurate (compared to the alternatives listed above) technique, Q/d, to develop a list of sources to conduct a four-factor analysis.

MPCA selected a Q/d threshold of 4, which is as aggressive as any Q/d in the country. This was particularly surprising given that visibility in Minnesota Class I areas is already below the uniform rate of progress (URP) “glide-path” and approaching natural visibility. Figure 1 through Figure 3 demonstrate the visibility trends for the Boundary Waters Canoe Area Wilderness (BWCAW), Voyageurs National Park (Voyageurs), and Isle Royal National Park. These figures match those provided by the MPCA.[3]

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[2] https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf?VersionId=QC2nPZHuAH1VYmm3EuhV9ABIGm5rQynb

[3] Minnesota Pollution Control Agency. 2022. Regional Haze Update - 2nd Implementation Period PowerPoint presentation. pg. 6-7.

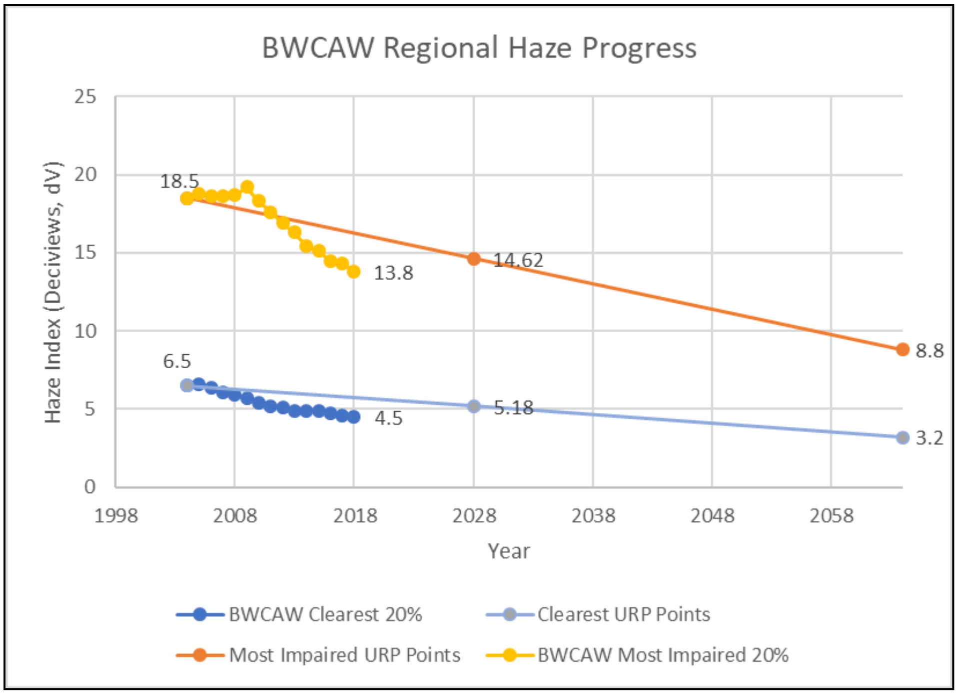

Figure 1 Visibility Trend versus URP – Boundary Waters Canoe Area (BOWA1)

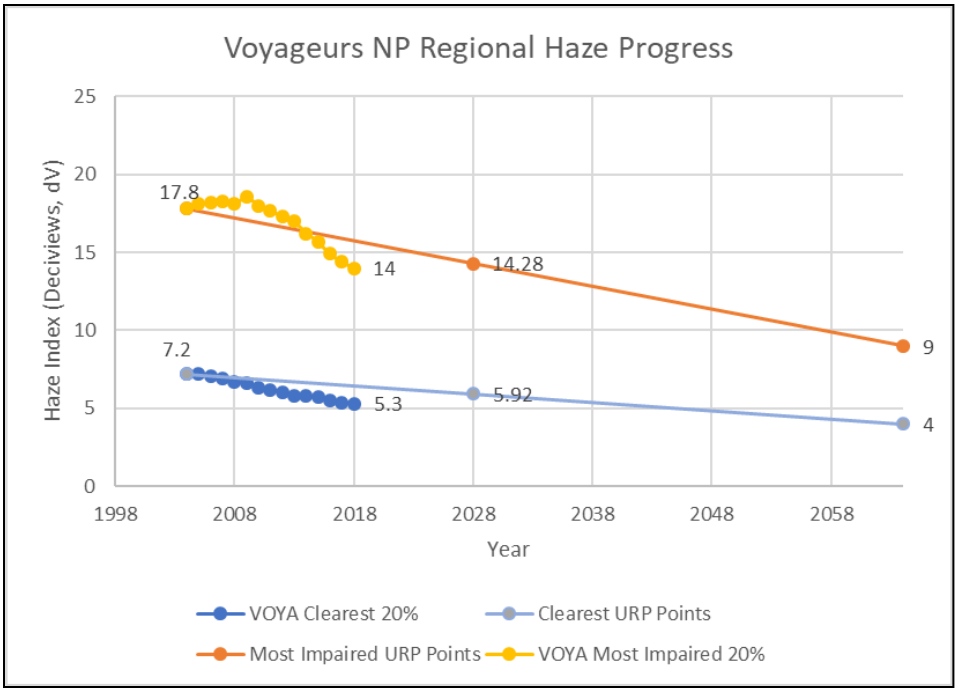

Figure 2 Visibility Trend versus URP – Voyageurs National Park (VOYA1)

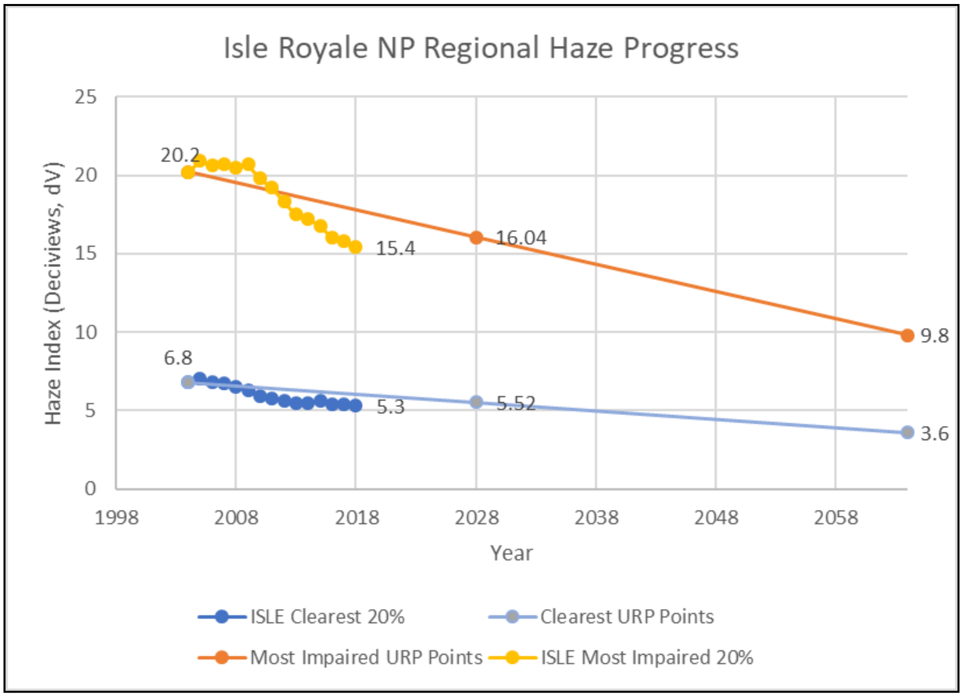

Figure 3 **Visibility Trend versus URP – Isle Royale National Park (ISLE1)**

Refer to Section 7 of SMBSC's original FFA for additional information supporting this position.

Notably, as part of Class I area Prevention of Significant Deterioration air permitting exercises, Federal Land Managers rarely evaluate permits at distances over 300 km and then only when sources are considerably larger than Boiler 1. They typically employ a Q/d of 10 to screen out sources from inclusion of visibility analysis on Class I areas[4].

While it may not have been unlawful per se for the MPCA to choose a Q/d of 4, there are extreme indications of arbitrariness when the MPCA applies a Q/d so dramatically more conservative than the Q/d the federal government itself uses for protecting Class I visibility. Overall, the danger of selecting such an aggressive screen is that it runs the risk of being over-inclusive, i.e., selecting facilities to perform a FFA that may make no contribution to visibility conditions in the Upper Midwest Class I areas.

For this reason, and because the MPCA specifically invited permittees to prepare supplemental analyses to accompanying the FFA, SMBSC prepared and included a trajectory analysis with the FFA, providing a more accurate picture of the relationship between SMBSC's emissions and conditions in the Upper Midwest Class I areas.

2 Wind Rose and Trajectory Analysis

SMBSC completed a wind rose for Olivia, MN Regional airport (located approx. 8 miles from SMBSC) using 2006 -2020 data (refer to Section 7 of SMBSC's FFA) shown in Figure 4.

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[4] https://www.fws.gov/guidance/sites/default/files/documents/FLAG%20Air%20Quality%20Phase%201%20report.pdf

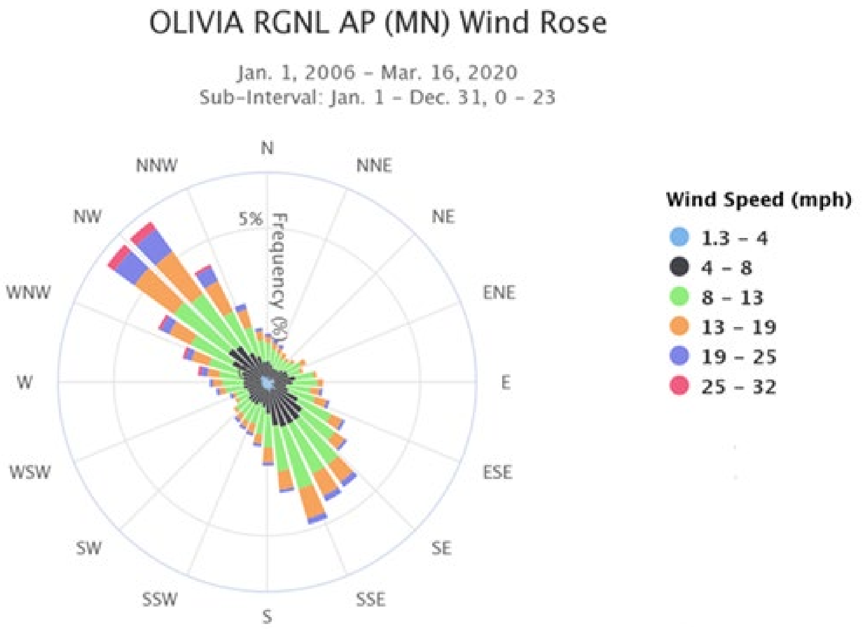
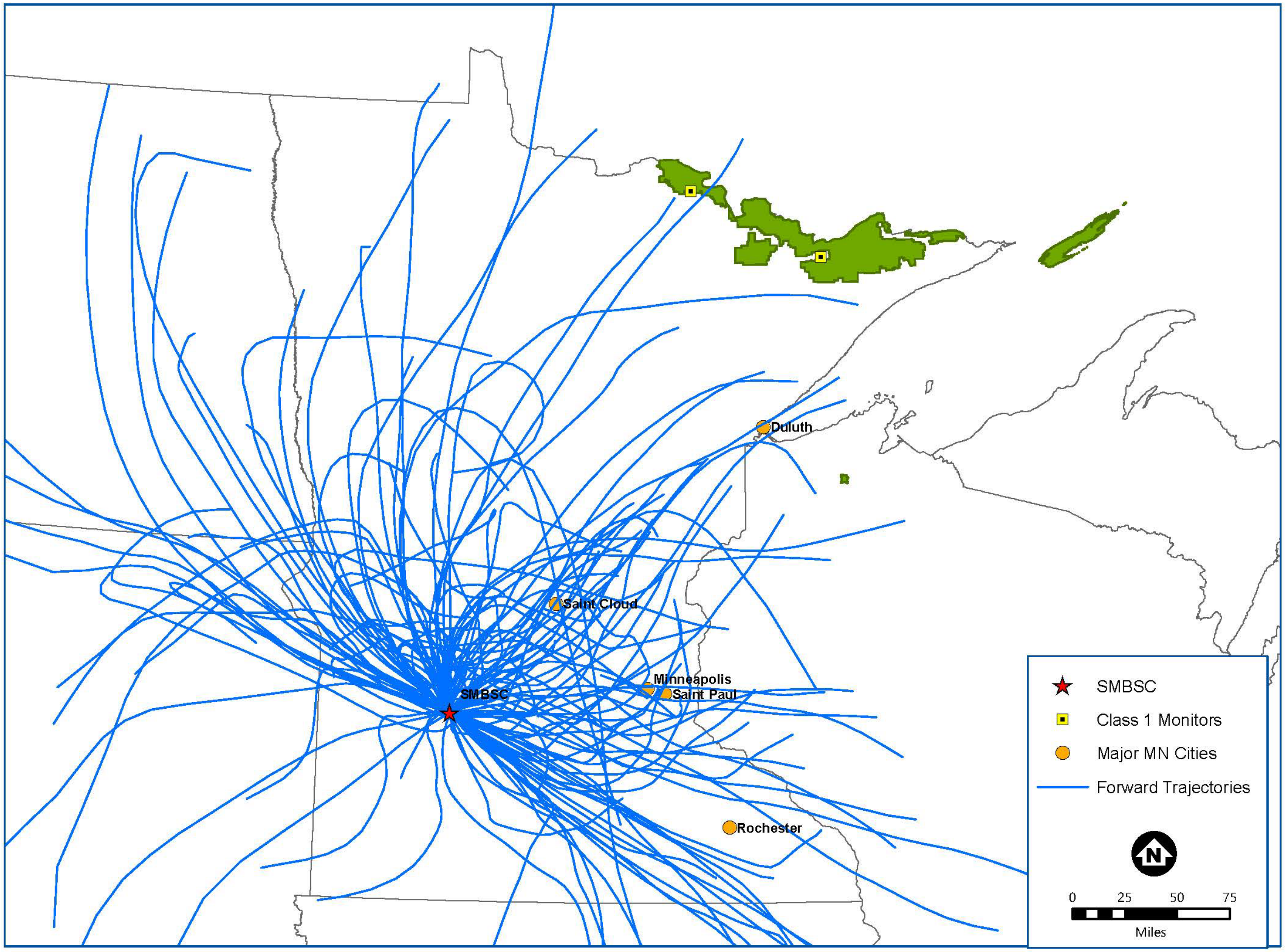


Figure 4 **Olivia Wind Rose**

This wind rose confirms that the predominant wind directions in this part of Minnesota are from the northwest and southeast/south-southeast, while all the Upper Midwest Class I Areas lie to the northeast. The wind frequency from the southwest that would be necessary to transport SMBSC emissions to any of the Class I areas is very small (less than 1% of the time). Again, the frequency of wind direction from SMBSC's location to the Class I areas is insignificant and compounded by SMBSC's 400-450 km distance to the nearest Class I area. Therefore, MPCA should consider this factor in any evaluation whether Boiler 1 would contribute to visibility impairment at the Upper Midwest Class I areas.

In addition, SMBSC included a forward-trajectory analysis with the original FFA submission (Figure 5), which is more accurate and sophisticated relative to MPCA's Q/d screening.


Duluth
Saint Cloud
Minneapolis
Saint Paul
SMBSC
Rochester
SMBSC
Class 1 Monitors
Major MN Cities
Forward Trajectories
N
0
25
50
75
Miles

The forward trajectory analysis was performed using 48-hour trajectories, consistent with the time period MPCA employs in calculating their back-trajectories. The analysis indicates that SMBSC's emissions seldom if ever reach the BWCAW or Isle Royale, and there is only a day or two each year the emissions even reach Voyageurs. Collectively, emissions from SMBSC only have the potential to reach Minnesota Class I areas in very rare circumstances, much less impact visibility. This by itself indicates that SNCR is not cost-effective.

3 Distance to Class I Areas

In addition, MPCA must consider the distance from SMBSC to the nearest Class I areas. Simply determining a cost-effective threshold that is universal for all facilities in Minnesota while disregarding distance is not appropriate for those facilities at the outer reaches of the screening distance. The distance from SMBSC is 400-450 km to both the BWCAW and Voyageurs and over 550 km to Isle Royale. Focusing on Voyageurs, which is the only location the trajectory analysis indicates SMBSC's emissions even reach, by the time the emissions reach Voyageurs the emissions have undergone maximum dispersion and attenuation. The distances alone are enough to eliminate SMBSC for consideration as part of any contribution analysis for the Class I areas. When both distance and prevailing winds are considered, the evidence clearly shows that that SNCR for Boiler 1 at SMBSC is not cost-effective.

4 Summary and Conclusion

SMBSC supports the MPCA goal for working to achieve reasonable progress for regional haze. However, given the 1) aggressive Q/d FFA screening criteria, 2) SMBSC's wind rose and trajectory analysis, 3) the distance to Class I areas, and 4) the absence of any countervailing evidence from the MPCA, the MPCA's request for SMBSC to install SNCR is unjustified, arbitrary, and contrary to law.

We appreciate your efforts in thoughtful consideration of SMBSC's position to MPCA's recommendation, and welcome the opportunity to have additional discussions towards a mutually agreeable path forward. Should you have any questions or comments regarding this submittal, please contact me by telephone at 320-329-4174 or via email at sagar@smbsc.com.

Sincerely,

Sagar...

Sagar Sunkavalli
Manager of Environmental Affairs

MINNESOTA POLLUTION
CONTROL AGENCY

520 Lafayette Road North | St. Paul, Minnesota 55155-4194 | 651-296-6300
800-657-3864 | Use your preferred relay service | info.pca@state.mn.us | Equal Opportunity Employer

January 29, 2020

Candice Maxwell, Area Manager - Environmental Affairs
United Taconite LLC - Fairlane Plant
1200 Highway 16
Forbes, MN 55738

RE: Request for Information - Regional Haze Rule, Reasonable Progress, Four Factor Analysis

Dear Ms. Maxwell:

The Minnesota Pollution Control Agency (MPCA) is currently preparing information for the second planning period (Round 2) comprehensive update to Minnesota's Regional Haze State Implementation Plan (SIP) as required by the Regional Haze Rule (40 CFR § 51.308). States are responsible for developing a Regional Haze SIP that addresses regional haze in each Class I area located within the state and in each Class I area located outside the state which may be affected by emissions from sources within the state. The Regional Haze SIP is required to identify existing facilities that cause or contribute to visibility impairment; analyze, identify, and apply federally-enforceable control strategies for those sources; and periodically demonstrate reasonable progress toward reaching visibility goals. States are also responsible for periodic comprehensive updates to their Regional Haze SIP that address these same topics. Minnesota's Round 2 Regional Haze SIP must be submitted to the U.S. Environmental Protection Agency (U.S. EPA) by July 31, 2021.

Minnesota has two Class I areas within its borders, the Boundary Waters Canoe Area Wilderness (BWCA) and Voyageurs National Park (Voyageurs). Other nearby Class I areas include Isle Royale National Park in Michigan. Therefore, Minnesota must prepare a Regional Haze SIP that identifies sources that cause or contribute to visibility impairment in these areas. To meet the core requirements for regional haze for these areas, Minnesota must submit a SIP that contains the plan elements and supporting documentation for all required analyses identified in 40 CFR § 51.308(f).

In the first planning period (Round 1), the focus of the Regional Haze Rule was on establishing Best Available Retrofit Technology (BART) for certain older sources and reasonable progress towards national visibility goals. In Round 2, there are no BART requirements; therefore, the focus is on making reasonable progress. The U.S. Environmental Protection agency has defined the methodology that states must use to determine what measures are necessary to make reasonable progress in 40 CFR § 51.308(f)(2). At minimum, the reasonable progress analysis must use the four factors identified in 40 CFR § 51.308(f)(2)(i) to evaluate and determine the emission reduction measures necessary to make reasonable progress. The four factors are:

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

Data from the IMPROVE monitoring sites at BWCA and Voyageurs indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X).

You are receiving this letter because your facility was identified as a significant source of NO_X and SO_2 and is located close enough to the BWCA or Voyageurs to potentially cause or contribute to visibility impairment in these Class I areas. Therefore, the MPCA requests that you prepare a "Four Factor Analysis" for the following emission units:

1. Line 1 Pellet Induration (EQUI 45 / EU 040) that addresses emissions of NO_X and SO_2
2. Line 2 Pellet Induration (EQUI 47 / EU 042) that addresses emissions of NO_X and SO_2

The analysis should be prepared using the U.S. Environmental Protection Agency guidance[1] that provides recommendations for how each of the factors should be determined.

Preparation of the comprehensive update to Minnesota's Regional Haze SIP will require extensive planning and review of sources in Minnesota. The MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to prepare the Regional Haze SIP. The MPCA expects air quality modeling of potential regional emissions reductions will be conducted beginning in spring 2020. I appreciate your attention to this matter and request that you **submit the Four Factor Analysis by July 31, 2020**.

If you have any questions regarding this matter, or would like to request a meeting to further discuss the contents of this letter, please contact me by phone at 651-757-2653 or by email at Hassan.Bouchareb@state.mn.us.

Sincerely,

Hassan Bouchareb

This document has been electronically signed.

Hassan M. Bouchareb
Engineer
Environmental Analysis and Outcomes Division

Cc: Chad Asgaard, United Taconite Company LLC
Jason Aagenes, Cleveland-Cliffs Inc.
Deepa de Alwis, MPCA
Cory Boeck, MPCA
Frank Kohlasch, MPCA
Agency Interest ID 140099

Address questions and submittals requested above to:

Hassan M. Bouchareb
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520 Lafayette Road North
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(651) 757-2653
Hassan.Bouchareb@state.mn.us

---

[1] **U.S. Environmental Protection Agency.** *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 20, 2019, https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

CLIFFS

CLEVELAND-CLIFFS INC.
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July 31, 2020

Mr. Hassan Bouchareb
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155-4194

Re: Four Factor Analysis for United Taconite LLC – Fairlane Plant

Dear Mr. Bouchareb:

United Taconite LLC – Fairlane Plant's (United) received a Request for Information (RFI) from the Minnesota Pollution Control Agency (MPCA), dated January 29, 2020, to conduct a Four-Factor analysis (analysis). This analysis was requested to aid MPCA in preparing for the second planning period updating Minnesota's Regional Haze State Implementation Plan (SIP). This analysis evaluated potential emission control measures for nitrogen oxides (NOx) and sulfur dioxide (SO2) for both of the indurating pellet furnace lines at United. As requested, enclosed you will find the results of that analysis, which was prepared using the U.S. Environmental Protection Agency guidance cited in the RFI.

Please contact me at (218) 744-7849 or at candice.maxwell@clevelandcliffs.com if you have questions about this submittal or require additional information.

Sincerely,

Candice Maxwell

Candice Maxwell
Area Manager – Environmental Affairs

Enclosure – "Regional Haze Four-Factor Analysis for NOx and SO2 Emission Control"

cc: C. Asgaard, UTAC
J. Aagenes, Cleveland-Cliffs
L. Koskela, UTAC

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

325 South Lake Avenue
Duluth, MN 55802
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Regional Haze Four-Factor Analysis for NO_X and SO_2 Emissions Control

July 31, 2020

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Appendix A: Unit Specific Screening Level Cost Summary for Line 1 Control Measures

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Abbreviations

BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BWCA	Boundary Waters Canoe Area
CAMx	Comprehensive Air Quality Model with Extensions
CEMS	Continuous Emissions Monitoring System
CEPCI	Chemical Engineering Plant Cost Index
CPI	Consumer Price Index
DSI	Dry Sorbent Injection
EFGR	External Flue Gas Recirculation
EPA	U.S. Environmental Protection Agency
ESP	Electrostatic Precipitator
FIP	Federal Implementation Plan
GSA	Gas Suspension Absorption
IMPROVE	Interagency Monitoring of Protected Visual Environments
Isle Royale	Isle Royale National Park
LADCO	Lake Michigan Air Directors Consortium
LNB	Low-NO_X Burners
LoTOx	Low Temperature Oxidation
MPCA	Minnesota Pollution Control Agency
NA	Not Applicable
NO	Nitric Oxide
NO_X	Nitrogen Oxides
NSCR	Non-Selective Catalytic Reduction
NSM	Northshore Mining Company
O_2	Oxygen
O&M	operating and maintenance
PM/PM10/PM2.5	Particulate Matter/PM<10 microns, PM<2.5 microns
PSD	Prevention of Significant Deterioration
PPM	Parts per Million
RACT	Reasonably Available Control Technology
RFI	Request for Information
RHR	Regional Haze Rule
RSCR	Regenerative Selective Catalytic Reduction
SCR	Selective Catalytic Reduction
SDA	Spray Dryer Absorption
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SO_3	Sulfur trioxide
TMDL	Total Maximum Daily Load

tpy	tons per year
TSD	Technical Support Document
ULNB	Ultra Low-NO_X Burners
UTAC	United Taconite LLC
Voyageurs	Voyageurs National Park

1 Executive Summary

In accordance with Minnesota Pollution Control Agency's (MPCA's) January 29, 2020 Request for Information (RFI) Letter,[1] United Taconite LLC Fairlane Plant (UTAC) evaluated potential emission control measures for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) for the Line 1 Pellet Indurating Furnace (EQUI 45/EU 040) and Line 2 Pellet Indurating Furnace (EQUI 47/EU 042), collectively referred to as the Line 1 and Line 2 Indurating Furnaces, as part of the state's demonstration of reasonable progress under the Regional Haze Rule (RHR).[2] The analysis considers potential emission control measures by addressing the four statutory factors laid out in 40 CFR 51.308(f)(2)(i) and pursuant to the final U.S. Environmental Protection Agency (EPA) RHR State Implementation Plan (SIP) guidance[3] dated August 20, 2019 (2019 RH SIP Guidance):

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

This report describes the background and analysis for conducting the Four-Factor analysis. Conclusions are summarized in Table 1-1 for NO_X and Table 1-2 for SO_2.

The NO_X 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),[4] 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.

In the Factor #1 – Cost of Compliance analysis, the associated cost-effectiveness ($ for each ton of emissions reduction) for SCR with reheat far exceeded a reasonable cost-effectiveness thresholds of $1,193 to $2,800 per ton for NO_X emission controls (refer to Sections 4.2 and 5.2 for more information).

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[1] January 29, 2020 letter from Hassan Bouchareb of MPCA to Candice Maxwell of UTAC.

[2] The U.S. Environmental Protection Agency (EPA) also refers to this regulation as the Clean Air Visibility Rule. The regional haze program requirements are promulgated at 40 CFR 51.308. The SIP requirements for this implementation period are specified in §51.308(f).

[3] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003.

[4] Federal Register 81, no. 70 (April 12, 2016); 21675. Available at: https://www.govinfo.gov/app/details/FR-2016-04-12/2016-07818

Therefore, the facility's existing NO_X emissions performance (refer to Section 3 for more information) is sufficient for the MPCA's regional haze reasonable progress goal.

The SO_2 Four-Factor Analysis evaluated the following SO_2 emission control measures:

- Dry Sorbent Injection (DSI) with New Particulate Matter (PM) Control
- Spray Dryer Absorption (SDA) with New PM Control
- Gas Suspension Absorption (GSA) with New PM Control

Similar to the NO_X control technology described above, none of these SO_2 control technologies have been successfully installed on a taconite furnace, and therefore, do not meet the definition of technically feasible. However, EPA required an evaluation of these SO_2 control technologies in the first round of Regional Haze Rule analysis.

In the Factor #1 – Cost of Compliance analysis, the associated cost-effectiveness ($ for each ton of emissions reduction) for each of the evaluated measures far exceeded a reasonable cost-effectiveness thresholds of $4,200 to $5,700 per ton for SO_2 emission controls (refer to Sections 4.2 and 6.2 for more information). Therefore, the facility's existing SO_2 emissions performance (refer to Section 3 for more information) is sufficient for the MPCA's regional haze reasonable progress goal.

In addition to the four statutory factors, states have the discretion to consider any potential visibility improvements, which is referred to as the "fifth factor." UTAC continues to evaluate visibility benefits associated with possible NO_X and SO_2 control measures internally and reserves the right to supplement this analysis with information related to visibility benefits and cost per deciview improvement. UTAC plans to conduct CAMx modeling after modeling information from the Lake Michigan Air Directors Consortium (LADCO) is available.

Table 1-1 Summary of NO_X Four-Factor Analysis

	Factor #1 Cost of Compliance						
List of Emission Control Measure	Installed Capital Cost ($)	Annualized Operating Cost ($/year)	Pollution Control Cost ($/ton)	Factor #2 Time Necessary for Compliance	Factor #3 Energy and Non Air Quality Environmental Impacts of Compliance	Factor #4 Remaining Useful Life of the Source	Does this Analysis Support the Installation of this Emission Control Measure?
SCR with Reheat	Line 1 - $43,637,895 Line 2 - $72,550,865	$21,350,897 $41,336,088	$32,228 $44,115	5 years after SIP promulgation. See Section 5.3.	<u>Energy</u> • Increased energy use to overcome the increased differential pressure; • Increased indirect emissions at power plant to accommodate the increased energy use. • Substantial increase in natural gas usage to reheat the exhaust stream; and • Additional electricity is required for the SCR equipment, to vaporize the aqueous ammonia reagent, and for additional fan power. <u>Environmental</u> • Unreacted ammonia (a PM_{10} precursor) would be emitted to the atmosphere (ammonia slip); • Ammonia would combine with NO_X and SO_2 to form ammonium salts, which would be emitted to the atmosphere as PM_{10}; • Sulfuric acid mist emissions will increase due to the	20-year control equipment life	No

	Factor #1 Cost of Compliance						
List of Emission Control Measure	Installed Capital Cost ($)	Annualized Operating Cost ($/year)	Pollution Control Cost ($/ton)	Factor #2 Time Necessary for Compliance	Factor #3 Energy and Non Air Quality Environmental Impacts of Compliance	Factor #4 Remaining Useful Life of the Source	Does this Analysis Support the Installation of this Emission Control Measure?
					oxidation of SO_2 to SO_3 by the SCR catalyst; • Emissions of ammonia, ammonium sulfates, and sulfuric acid mist increase plume visibility and contribute to regional haze; • Increased oxidized mercury emissions. • There are safety risks associated with the transportation, handling, and storage of aqueous ammonia; and • Spent catalyst from the SCR is typically disposed of in a landfill; however, catalyst recycling or reconditioning may be available.		

Table 1-2 Summary of SO_2 Four-Factor Analysis

	Factor #1 Cost of Compliance							
List of Emission Control Technology	Installed Capital Cost ($)	Annualized Operating Cost ($/year)	Pollution Control Cost ($/ton)	Factor #2 Time Necessary for Compliance	Factor #3 Energy and Non Air Quality Environmental Impacts of Compliance	Factor #4 Remaining Useful Life of the Source	Does this Analysis Support the Installation of this Emission Control Measure?
Line 1 DSI, SDA and GSA with new PM Control	Not applicable – See Section 6.1.	NA	NA	NA	NA	NA	NA
Line 2 DSI with new PM Control	$50,466,157	$10,090,749	$93,300	5 years after SIP promulgation. See Section 6.3.	Energy Increased energy use to accommodate differential pressure. Increased indirect emissions at power plant to accommodate the increased energy use. Environmental Additional solid waste generation and disposal. Lost production due to loss of recycled dust that contains valuable iron units.	20-year control equipment life	No

	Factor #1 Cost of Compliance						
List of Emission Control Technology	**Installed Capital Cost ($)**	**Annualized Operating Cost ($/year)**	**Pollution Control Cost ($/ton)**	**Factor #2 Time Necessary for Compliance**	**Factor #3 Energy and Non Air Quality Environmental Impacts of Compliance**	**Factor #4 Remaining Useful Life of the Source**	**Does this Analysis Support the Installation of this Emission Control Measure?**
Line 2 SDA with new PM Control	$120,947,748	$19,573,967	$180,891	5 years after SIP promulgation. See Section 6.3.	Energy Increased energy use to accommodate differential pressure. Increased indirect emissions at power plant to accommodate the increased energy use. Environmental Additional solid waste generated and disposed.	20-year control equipment life	No
Line 2 GSA with new PM Control	$113,793,152	$18,757,651	$173,347	5 years after SIP promulgation. See Section 6.3.	Increased energy use to accommodate differential pressure. Increased indirect emissions at power plant to accommodate the increased energy use. Environmental Additional solid waste generation and disposal.	20-year control equipment life	No

2 Introduction

This section summarizes the relevant regulatory background and provides a description of UTAC's indurating furnaces.

2.1 Four-Factor Analysis Regulatory Background

The RHR published on July 15, 2005 by the EPA defines regional haze as "visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources." The RHR requires state regulatory agencies to submit a series of SIPs in ten-year increments to protect visibility in certain national parks and wilderness areas, known as mandatory Federal Class I areas. The original state SIPs were due on December 17, 2007 and included milestones for establishing reasonable progress towards the visibility improvement goals, with the ultimate goal of achieving natural background visibility by 2064. The original SIP was informed by best available retrofit technology (BART) analyses that were completed on all subject-to-BART sources. The second RHR planning period requires development and submittal of updated state SIPs by July 31, 2021.

On January 29, 2020, the MPCA sent an RFI to UTAC. The RFI stated that data from the Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring sites at Boundary Waters Canoe Area (BWCA) and Voyageurs National Park (Voyageurs) indicate that nitrates and sulfates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of nitrates and sulfates are emissions of NO_X and SO_2. In addition, emissions from sources in Minnesota could potentially impact Class I areas in nearby states, namely Isle Royale National Park (Isle Royale) in Michigan. Although Michigan is responsible for evaluating haze at Isle Royale, Michigan must consult with surrounding states, including Minnesota, on potential cross-state haze pollution impacts. As part of the planning process for the SIP development, MPCA is working with the LADCO to evaluate regional emission reductions.

The RFI also identified the UTAC facility as a significant source of NO_X and SO_2 that is located close enough to BWCA and Voyageurs to potentially cause or contribute to visibility impairment. Therefore, the MPCA requested that UTAC submit a "Four-Factor Analysis" by July 31, 2020 for the emission units identified in Table 2-1 as part of the state's regional haze reasonable progress.

Table 2-1 Identified Emission Units

Unit	Unit ID	Applicable Pollutants
Line 1 Pellet Induration	EQUI 45 / EU 040	NO_X and SO_2
Line 2 Pellet Induration	EQUI 47 / EU 042	NO_X and SO_2

The analysis considers potential emission control measures by addressing the four statutory factors, which are laid out in 40 CFR 51.308(f)(2)(i) and explained in the 2019 RH SIP Guidance.[5]

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

The RFI specified that the "... analysis should be prepared using the U.S. Environmental Protection Agency guidance" referring to the final 2019 RH SIP Guidance.

This report presents the Four-Factor Analysis for NO_X and SO_2 as applied to the review of emission controls at UTAC for the emission units identified in Table 2-1.

2.2 UTAC Description

UTAC mines iron ore (magnetite) and produces taconite pellets that are shipped to steel producers for processing in blast furnaces. The iron ore is crushed and routed through several concentration stages including grinding, magnetic separation, and thickening.

The concentrated iron ore slurry is then dewatered, filtered, mixed with bentonite and/or other binding agents, and formed into greenballs, which are fed onto the traveling grate of the indurating furnace. Figure 2-1 depicts a typical grate-kiln indurating furnace configuration, similar to UTAC's Line 1 and Line 2 Indurating Furnaces.

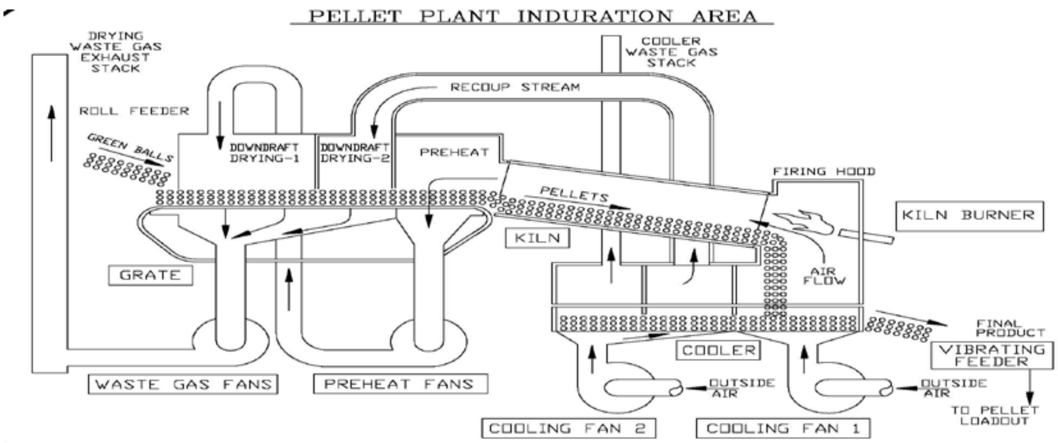

Figure 2-1 Typical Grate-Kiln Indurating Furnace Configuration

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[5] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003.

3 Existing Controls and Baseline Emission Performance

This section describes the existing NO_X and SO_2 emission controls on UTAC's indurating furnaces and the baseline emissions that are used to evaluate the cost-effectiveness for the associated emission control measures.

3.1 Existing Emission Controls

In 2006 and 2007, UTAC submitted to MPCA its BART analysis and supplemental analysis that evaluated NO_X and SO_2 control strategies for the indurating furnaces. MPCA subsequently developed its SIP with certain NO_X and SO_2 reductions for various facilities state-wide and submitted the SIP to EPA for approval. EPA partially disapproved Minnesota's SIP and promulgated Federal Implementation Plan (FIP) requirements in 2013. UTAC'S 2013 FIP limits were subject to a legal challenge as being technically infeasible and were subsequently replaced with alternate FIP limits that were published in the Federal Register on April 12, 2016.[6] The 2016 FIP imposed NO_X emission limits on UTAC'S furnaces of 2.8-3.0 lb NO_X/MMBtu when only natural gas is combusted and 1.5-2.5 lb NO_X/MMBtu for all other fuels, on a 720-hour rolling average basis. For SO_2, the 2016 FIP imposed an emission limit of 529 lb SO_2/hr, based on a 30-day rolling average, for both furnaces combined.

In addition, UTAC proposed NO_X emission limits in its 2010 Title V Major Amendment that represented a 2,415 ton per year NO_X reduction from BART baseline levels. MPCA established these reductions as enforceable BART limits for UTAC in the form of an 816 ton and 1,820 ton limit for Line 1 and Line 2, respectively, on a 180-day rolling basis. These limits remain in effect in UTAC'S current Title V permit and, in conjunction with the 2016 FIP emission limits, are reflected in how the facility currently operates with regard to developing baseline, future expected emission levels for this Four-Factor Analysis evaluation.

3.2 Baseline Emissions Performance

The Four-Factor Analysis requires the establishment of a baseline scenario for evaluating a potential emission control measure. On page 29 of the 2019 RH SIP Guidance in the section entitled "Baseline control scenario for the analysis," excerpted below, EPA considers the projected 2028 emissions scenario as a "reasonable and convenient choice" for the baseline control scenario:

> *"Typically, a state will not consider the total air pollution control costs being incurred by a source or the overall visibility conditions that would result after applying a control measure to a source but would rather consider the incremental cost and the change in visibility associated with the measure relative to a baseline control scenario. The projected 2028 (or the current) scenario can be a*

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[6] Federal Register 81, no. 70 (April 12, 2016); 21675. Available at: https://www.govinfo.gov/app/details/FR-2016-04-12/2016-07818.

> *reasonable and convenient choice for use as the baseline control scenario for measuring the incremental effects of potential reasonable progress control measures on emissions, costs, visibility, and other factors. A state may choose a different emission control scenario as the analytical baseline scenario. Generally, the estimate of a source's 2028 emissions is based at least in part on information on the source's operation and emissions during a representative historical period. However, there may be circumstances under which it is reasonable to project that 2028 operations will differ significantly from historical emissions. Enforceable requirements are one reasonable basis for projecting a change in operating parameters and thus emissions; energy efficiency, renewable energy, or other such programs where there is a documented commitment to participate and a verifiable basis for quantifying any change in future emissions due to operational changes may be another. A state considering using assumptions about future operating parameters that are significantly different than historical operating parameters should consult with its EPA Regional office."*

Based on EPA guidance, the estimate of a source's 2028 emissions is based at least in part on information on the source's operation and emissions during a representative historical period. MPCA has recommended utilizing reporting year 2017 emissions as the basis for estimating for 2028 baseline emissions.

The estimated 2028 baseline NO_X emissions to be used for the Four-Factor Analyses are 1,325 tpy for the Line 1 Indurating Furnace and 1,874 tpy for the Line 2 Indurating Furnace. The 2028 baseline emission values were calculated from the 2017 air emission inventory actual hourly emissions as collected by UTAC's continuous emission monitoring system (CEMS), and adjusted to conform with the FIP limits of 3.0 lb NOx/MMBtu during periods when only natural gas is combusted, and with the FIP limits of 2.5 lb NOx/MMBtu during periods when all other fuels are used, including mixed fuel usage.

The estimated 2028 baseline SO_2 emissions to be used for the Four-Factor Analyses are 59.7 tpy for the Line 1 Indurating Furnace and 215.4 tpy for the Line 2 Indurating Furnace, and were based on data collected by UTAC's CEMS used for the 2017 air emission inventory. These emission rates, combined, are substantially less than the BART emission rate of 529 lb/hr (for both furnaces combined), which equates to 2,317 tons per year.

4 Four-Factor Analysis Overview

This section summarizes the Four-Factor Analysis approach with respect to the Regional Haze program detailed in the 2019 RH SIP guidance.

4.1 Emission Control Options

Prior to completing a Four-Factor Analysis of each emission control measure, all technically feasible emission control options for the indurating furnaces must first be identified. Potentially available emission control measures include both physical and operational changes. Once all technically feasible emission control measures are identified, the facility justifies which emission control measures are reasonable to consider against the four factors, recognizing there is no statutory or regulatory requirement to consider all technically feasible measures or any particular measures.

Under normal circumstances, a potential emission control measure must have been previously installed and operated successfully on a similar source under similar physical and operating conditions to be considered technically feasible. However, for the purpose of this technology screening analysis, available control measures which have been commercially demonstrated in other industrial combustion applications, outside of taconite processing, have been considered in this analysis. UTAC does not concede that any technology discussed in this analysis would definitively be technically appropriate for taconite indurating applications. Accordingly, UTAC reserves the right to re-evaluate and modify this analysis to more closely examine the technical appropriateness of utilizing these industrial control measures for the taconite indurating process, if necessary. Novel controls that have not been demonstrated on full-scale, industrial operations are not considered as part of this analysis.

While the 2006 BART report included a comprehensive list of control measures and a rigorous screening of all available NO_X and SO_2 control technologies; most of the control technologies were excluded from the 2006 BART and subsequent BART analyses because they were not "generally available" or "available to an indurating furnace." A recent review of the availability status confirmed no material changes since the BART reports (i.e., they are still not "generally available" or "available to an indurating furnace"). This Four-Factor Analysis is building on the 2006 BART and subsequent BART analyses and only re-evaluating a reasonable set of NO_X and SO_2 control technologies. Only controls that may be technically feasible were considered. Control technologies with significant adverse environmental impacts were excluded from the set of reasonable control technologies.

The control effectiveness of UTAC's existing emission control measures established in the 2016 FIP are 2.8-3.0 lb NO_X/MMBtu for natural gas only and a limit of 1.5-2.5 lb NO_X/MMBtu for all other fuels, on a 720-hour rolling average basis. For SO_2, the FIP required an aggregate Line 1 and Line 2 Indurating Furnaces emission limit of 529 lb SO_2/hr, based on a 30-day rolling average. For purposes of this analysis, UTAC evaluated only those control measures that have the potential to achieve an overall pollutant reduction greater than the performance of the existing systems, including optimizations.

An evaluation of the control measures for NO_X and SO_2 are discussed in Sections 5.1 and 6.1, respectively.

4.2 Factor #1 – Cost of Compliance

Factor #1 estimates the capital and annual operating and maintenance (O&M) costs of the control measure. As directed by the 2019 RH SIP Guidance (page 21), the costs of emission controls follow the accounting principles and generic factors from the EPA Air Pollution Control Cost Manual (EPA Control Cost Manual), [7] unless more refined site-specific estimates are available. Under this step, the annualized cost of installation and operation on a dollars per ton of pollutant removed ($/ton) of the control measure, referred to as "average cost-effectiveness," is compared to a cost-effectiveness threshold that is estimated by EPA.

The UTAC 2006 BART report established NO_X and SO_2 cost-effectiveness thresholds of $1,000 to $1,300 per ton removed based on the BART final rule, court cases on cost-effectiveness, guidance from other regulatory bodies, and other similar regulatory programs like the Clean Air Interstate Rule (CAIR), and cost-effective air pollution controls in the electric utility industry for large power plants. The lower threshold of $1,000 per ton in 2006 is scaled to today's dollars using the Chemical Engineering Plant Cost Index (CEPCI).[8] The CEPCI is an industrial plant index that is considered more representative for purposes of this analysis than general cost indices such as the Consumer Price Index (CPI). The average cost-effectiveness threshold in current dollars is calculated to be $1,193 per ton. More recently, Pennsylvania Department of Environmental Department established a Reasonably Available Control Technology (RACT) cost-effectiveness of $2,800 per ton of NO_X controlled in the 2019 SIP.[9] Therefore, a screening cost-effective threshold range of $1,193 to $2,800 would be considered reasonable.

Review of BART cost-effectiveness thresholds for SO_2 were found in the 2014 Texas and Oklahoma RH FIP, citing a cost-effectiveness threshold for SO_2 of $4,000 to $5,000 per ton of SO_2 controlled.[10] Adjusting the 2014 threshold to current dollars results in a range of $4,200 to $5,700. Therefore, a cost-effective threshold range of $4,200 to $5,700 would be considered reasonable.

Generally, if the average cost-effectiveness is greater than an acceptable threshold, the cost is considered to not be reasonable. Conversely, if the average cost-effectiveness is less than the threshold, then the cost is considered reasonable for purposes of Factor #1, pending an evaluation of whether the absolute cost of control (i.e., costs in absolute dollars, not normalized to $/ton) is unreasonable. This situation is

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[7] US EPA, "EPA Air Pollution Control Cost Manual, Sixth Edition," January 2002, EPA/452/B-02-001. The EPA has updated certain sections and chapters of the manual since January 2002. These individual sections and chapters may be accessed at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution as of the date of this report.

[8] More information on CEPCI may be found at this link: https://www.chemengonline.com/pci-home. The CEPCI is accessible by subscription through "Chemical Engineering" magazine. The CEPCI scaling factors for this analysis compare 2006 values to January 2020 values.

[9] U.S. EPA PADEP SIP, June 10, 2019. https://www.federalregister.gov/documents/2019/05/09/2019-09478/approval-and-promulgation-of-air-quality-implementation-plans-pennsylvania-regulatory-amendments

[10] U.S. EPA TX and OK FIP, December 16, 2014. https://www.govinfo.gov/content/pkg/FR-2014-12-16/pdf/2014-28930.pdf

particularly applicable to a source with existing emission controls with an intermediate or high degree of effectiveness, as is the case with the indurating furnaces due to their existing NO_X and SO_2 emission controls.

The cost of an emission control measure is derived using capital and annual O&M costs. Capital costs generally refer to the money required to design and build the system. This includes direct costs, such as equipment purchases, and installation costs. Indirect costs, such as engineering and construction field expenses and lost revenue due to additional unit downtime in order to install the additional control measure(s), are considered as part of the capital calculation. Annual O&M costs include labor, supplies, utilities, etc., as used to determine the annualized cost in the numerator of the cost-effectiveness value. The denominator of the cost-effectiveness value (tons of pollutant removed) is derived as the difference in: 1) projected emissions using the current emission control measures (baseline emissions), as described in Section 3.2, in tons per year (tpy), and 2) expected annual emissions performance through installation of the additional control measure (controlled emissions), also in tpy.

When UTAC was originally constructed, major processing equipment was installed first, and the buildings were erected around the equipment. Due to the very limited space around existing equipment, a 60 percent markup of the total capital investment (i.e., a 1.6 retrofit factor) was included in the costs to account for the retrofit installation. Retrofit installations have increased handling and erection difficulty for many reasons. Access for transportation, laydown space, etc. for new equipment is significantly impeded or restricted. This is because the spaces surrounding the furnaces are congested, or the areas surrounding the building support frequent vehicle traffic or crane access for maintenance. The structural design of the existing building would not support additional equipment on the roof. Additionally, the technologies evaluated in this section are complex and increase the associated installation costs (e.g., ancillary equipment requirements, piping, structural, electrical, demolition, etc.). The use of a retrofit factor has been justified by previous BART projects and with UTAC and the MPCA.[11] Finally, the EPA Air Pollution Control Cost Manual notes that retrofit installations are subjective because the plant designers may not have had the foresight to include additional floor space and room between components for new equipment.[12] Retrofits can impose additional costs to "shoehorn" equipment in existing plant space, which is true for UTAC.

For purposes of calculating cost-effectiveness and as described in Section 3.2, UTAC uses NO_X 2028 baseline emission values of 1,325 tpy for the Line 1 Indurating Furnace and 1,874 tpy for the Line 2 Indurating Furnace. The 2028 baseline emission values were calculated from the 2017 air emission inventory actual hourly emissions, and adjusted to conform with the FIP limits of 3.0 lb NOx/MMBtu

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[11] Barr Engineering Co. United Taconite Analysis of Best Available Retrofit Technology. 2006 and U. S. Environmental Protection Agency. Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze (final rule, to be codified at 40 CFR Part 52). Federal Register. January 30, 2014. Vol. 79, 20, p. 5154. EPA–R08–OAR–2012–0026.

[12] U.S. Environmental Protection Agency. EPA Air Pollution Control Cost Manual, Sixth Edition, Section 1, Chapter 2.6.4.2 Retrofit Cost Considerations. 2017. https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

during periods when only natural gas is combusted, and with the FIP limits of 2.5 lb NOx/MMBtu during periods when all other fuels are used, including mixed fuel usage.

For SO_2, the 2028 baseline emissions to be used are 59.7 tpy for the Line 1 Indurating Furnace and 215.4 tpy for the Line 2 Indurating Furnace.

4.3 Factor #2 – Time Necessary for Compliance

Factor #2 considers the time needed for UTAC to comply with potential emission control measures. This includes the planning, installation, and commissioning of the selected control based on experiences with similar sources and source-specific factors.

For the purposes of this analysis and if a given NO_X or SO_2 control measure requires a unit outage as part of its installation, UTAC considers the forecasted outage schedule for the associated units in conjunction with the expected timeframe for engineering and equipment procurement. However, due to the potential control technology project’s significant capital expenditure, physical size and complexity, the installation may not be able to be accomplished during scheduled outages and could potentially require additional time beyond a scheduled major outage. In addition, most control technology equipment requires long-lead times for design and procurement that could result in the installation occurring outside a scheduled outage or could result in further delays in construction of the project to align with the next scheduled major outage.

4.4 Factor #3 – Energy and Non-Air Quality Environmental Impacts of Compliance

Factor #3 considers the energy and non-air quality environmental impacts of each potential emission control measure. Energy impacts to be considered are the direct energy consumed at the source, in terms of kilowatt-hours or mass of fuels used. Non-air quality environmental impacts may include solid or hazardous waste generation, wastewater discharges from a control device, increased water consumption, and land use. The analysis is conducted based on consideration of site-specific circumstances.

4.5 Factor #4 – Remaining Useful Life of the Source

Factor #4 considers the remaining useful life of the source, which is the difference between the date that additional emission controls will be put in place and the date that the facility would be expected to permanently ceases operation. Generally, the remaining useful life of the source is assumed to be longer than the useful life of the emission control measure unless the source is under an enforceable requirement to cease operation. In the presence of an enforceable end date, the cost calculation can use a shorter period to amortize the capital cost.

For the purposes of this evaluation, the remaining useful life for the units are assumed to be longer than the useful life of the evaluated additional emission controls measures. Therefore, the expected useful life of the evaluated control measure is used to calculate the emissions reductions, amortized costs, and the resulting cost per ton removed.

5 NO_X Four-Factor Analysis

This section identifies and describes various NO_X emission control measures, evaluates the four statutory factors for the Line 1 and Line 2 Indurating Furnaces, considers other factors, and determines if an emission control measure or measures are potentially feasible. Consistent with EPA's guidance and MPCA direction, UTAC has completed a Four-Factor Analysis for NO_X as described in Sections 5.1 to 5.6.

5.1 NO_X Control Measures Overview

Three mechanisms by which NO_X production typically forms are thermal, fuel and prompt NO_X formation. In the case of natural gas combustion, the primary mechanism of NO_X production is through thermal NO_X formation. This mechanism arises from the thermal dissociation of nitrogen and oxygen molecules in combustion air to nitric oxide (NO). The thermal oxidation reaction is as follows:

$$N_2 + O_2 \rightarrow 2NO \tag{1}$$

Downstream of the flame, significant amounts of NO_2 can be formed when NO is mixed with air. The reaction is as follows:

$$2NO + O_2 \rightarrow 2NO_2 \tag{2}$$

Thermal oxidation is a function of the residence time, free oxygen, and peak reaction temperature.

Fuel bound NO_X is primarily a concern with solid and liquid fuel combustion sources; it is formed as nitrogen compounds in the fuel are oxidized in the combustion process. Natural gas has minimal fuel bound nitrogen which eliminates fuel bound NO_X as a major concern.

Prompt NO_X is a form of thermal NO_X which is generated at the flame boundary. It is the result of reactions between nitrogen and hydrocarbon radicals generated during combustion. Only minor amounts of NO_X are emitted as prompt NO_X.

As stated in Section 4.1, this Four-Factor Analysis is building on the 2006 BART and subsequent BART analyses and only re-evaluating a reasonable set of control technologies. A recent review of the availability status confirmed no material changes since the 2006 BART and subsequent BART reports (i.e., they are still not "generally available" or "available to an indurating furnace"). Based on this review, SCR – Post Scrubber with Conventional Duct Burner Reheat was considered for further evaluation as the NO_X control measure for the Line 1 and Line 2 Indurating Furnaces. The following describes pertinent technical information regarding the technology and whether the technology is technically feasible as applied to the Line 1 and Line 2 Indurating Furnaces.

5.1.1 SCR – Post-Scrubber with Conventional Duct Burner Reheat

According to EPA's 2016 Final FIP,[13] 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.*

Past NO_X control equipment evaluations (2006 BART, 2010 Keetac Best Available Control Technology (BACT), and 2011 Essar BACT reports) considered SCR as technically feasible, whereas in the 2016 Final FIP,[14] EPA considered SCR as technically infeasible and stated the following:

> *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.*

Based on the information presented above, UTAC has identified SCR with reheat to carry forward through the Four-Factor Analysis and to be considered whether its installation is necessary to make reasonable progress based on the factors presented below. This analysis should not be interpreted to mean that UTAC considers SCR with reheat to be technically feasible. For a control technology to be considered technically feasible, it must have been previously installed and operated successfully on a similar source under similar physical and operating conditions. No such examples exist. As noted, the LKAB facility is pursuing other NO_X reduction options instead of SCR with reheat, thereby confirming the control technology has not been proven to be technically feasible.

At this time, the true cost of compliance for SCR with reheat cannot be fully quantified since this technology has not been proven to be technically feasible on a taconite furnace. Therefore, the cost of compliance should be considered a theoretical cost estimate based on the numerous assumptions needed to complete the cost evaluation for the NO_X emission control measures. Such assumptions include sizing of the equipment, catalyst compatibility, ammonia slip concentration, control efficiency, and many others.

The application of SCR on taconite furnaces differs fundamentally from its application on utility boilers due to the differences in gas composition, dust loading, and chemistry. The most serious issues yet to be resolved with SCR on furnaces include the formation of SO_3 in the reactor, the ability to inject ammonia at

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[13] Federal Register 81, no. 70 (April 12, 2016); 21675. Available at: https://www.govinfo.gov/app/details/FR-2016-04-12/2016-07818

[14] Ibid

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

Some of the issues confronted by utility boilers with SCR systems on units firing sulfur-bearing fuels involve secondary impacts from the SCR system. The taconite industry would expect to experience similar issues when applying SCR technology. These impacts include the formation of SO_3 in the reactor, the emissions of unreacted ammonia from the reactor, and formation of byproducts from the reaction such as ammonia salts and PM_{10}. These effects are often interconnected because SO_3 and unreacted ammonia can react within, and downstream of the SCR reactor. The same catalyst that promotes the reactions between ammonia and NO_X also promotes the oxidation of SO_2 to SO_3. Typically, a conversion of one to two percent of SO_2 to SO_3 could be expected. It is important to understand that SO_2 oxidation is dependent on other SCR design parameters. When high levels of catalyst activity are needed to target high NO_X reduction efficiencies and low levels of ammonia slip, or to counteract significant catalyst deactivation rates, SO_2 oxidation rates would be expected to increase. If lower levels of SO_2 oxidation are targeted, NO_X reduction, ammonia slip, or both must be compromised.[15] The potential increase of PM_{10} and $PM_{2.5}$ due to the increase in sulfuric acid mist emissions and condensable PM in the form of ammonium sulfate could trigger air permitting. Further, permitting could be complicated by triggering air permitting for NO_X control technology installation that results in collateral prevention of significant deterioration (PSD) pollutant increases.

There are several reasons why industries are concerned about the level of SO_2 oxidation in an SCR reactor. In the absence of other interactions, downstream equipment that operates below the sulfuric acid dew point can experience severe corrosion. In addition, SO_3 and sulfuric acid mist formed in such equipment can promote the formation of a visible plume, or a blue plume.[16] To meet visible emission limitations, a wet scrubber after the SCR with reheat is essential to control corrosion and to minimize the possibility of a visible plume. Costs associated with the wet scrubber control technology to control SO_3, sulfuric acid mist, corrosion control, and mitigating potential visible plume, would need to be factored into the cost of control evaluation for SCR with reheat. Due to the uncertainty with the sizing of the wet scrubber, the additional wet scrubber costs have not been incorporated at this time.

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[15] Cichanowicz, J. E. 1999. What You Should Know Before Specifying SCR. Power Magazine. May/June 1999. pp. 80-81.

[16] Moretti, A. L., Triscori, R. J., and Ritzenthaler, D. P. (2006). A System Approach to SO_3 Mitigation. Presented at the "EPRI-DOE-EPA-AWMA Combined Power Plant Air Pollutant Control Mega Symposium," August 28–31.

NO_X Variability and Ammonia Slip

Unlike a typical utility boiler operating at a steady load, taconite indurating furnaces typically experience significant variability in NO_X concentrations in the exhaust stream. As previously noted, thermal NO_X formation in an indurating furnace is the dominant mechanism for the formation of NO_X emissions. The rate of NO_X generation due to the thermal formation mechanisms indicates that the emissions are directly related to the peak gas temperature. Slight changes in the peak temperatures in the burner flame can have a large impact on the short-term NO_X concentrations. The NO_X formation–peak temperature relationship is a primary factor why the variability of NOx concentrations experienced in an indurating furnace is greater than in coal-fired boilers.

The NO_X variability is dependent on the individual indurating furnace design and operations. The differences in the magnitude of the NO_X variability and the average NO_X concentrations are due mainly to the differences in oxygen levels and temperature profiles existing within the furnace. An SCR system applied to an indurating furnace will most likely be confronted with highly variable inlet NO_X loadings and would have to be controlled to ensure the ammonia and NO_X molar ratio remains consistent during the short-term NO_X concentration variations. Overfeeding reagent (ammonia or urea) could lead to excessive ammonia slip and the formation of air pollutants such as ammonia sulfate which adversely affects visibility. The requirement for tight ammonia and NO_X molar ratios would reduce the overall NO_X control efficiency of an SCR system on an indurating furnace. As noted by Solnhofen cement manufacturing facility management, the NO_X variability caused a reduction in overall control efficiency. The SCR with reheat could achieve an 80 percent reduction periodically. However, the average control efficiency experienced was 50 percent.[17]

Mercury Oxidation

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.

Indurating Furnace Exhaust Dust

Although the SCR system would be located downstream of particulate controls, the SCR catalyst would be exposed to dust and spent SO_2 control reagents. Constituents in the indurating furnace exhaust gas

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[17] The Experience of SCR at Solnhofen and its Applicability to US Cement Plants, June 6, 2006. http://files.dep.state.pa.us/air/AirQuality/AQPortalFiles/Pollutants/transport/Comments/Lehigh_Attachment_Solnhofen.pdf

stream could adversely affect the SCR catalyst and increase adverse pollutant introduction to the exhaust stream.

The indurating furnace dust cannot be removed by normal soot blowing techniques as used in utility boilers due to design differences between utility boilers and indurating furnaces. Therefore, any accumulation of dust in the SCR system will have to be removed by shutting down the SCR system for cleaning. Cleaning of the SCR system could require shutdown of the indurating furnace and result in lost production due to the required maintenance activities. Additional costs would be expected from the lost production to accommodate the maintenance activities that would be in addition to the cost of control estimate for the SCR with reheat NO_X control technology. The exhaust dust loading could also shorten SCR run time between maintenance shutdowns by causing unacceptable pressure drops across the SCR system as dust accumulates.

Most of the NO_X reduction in an SCR reactor occurs within the catalyst pores. Sulfuric acid reacts with alkali earth metals to form sulfate compounds, which blind catalyst pores. Iron oxide catalyzes the conversion of SO_2 to sulfuric acid; creating more catalyst blinding compounds.

5.2 Factor #1 – Cost of Compliance

UTAC has completed cost estimates for the selected NO_X emission control measure of SCR with reheat. Due to the limited time available to respond to MPCA's request, conservative assumptions were made in the cost estimates for equipment costs. These include:

- Use of EPA SCR control costs developed for utility boilers, including estimating an equivalent heat input rate using the actual stack flow and calculating an effective heat input using the natural gas F-factor. As noted by non-utility boiler associations such as the Portland Cement Association, the EPA SCR control cost analysis severely underestimates the cost to install and operate an SCR control system on non-utility boiler processes.[18]
- A 2 part per million (ppm) ammonia slip to minimize collateral visibility emissions of ammonia and $PM_{2.5}$
- A control efficiency of 50 percent based on Portland Cement Association report.[19] The Portland Cement Association has performed comprehensive studies. This data was used to demonstrate the uncertainties and challenges associated with control technology transfers from the utility sector to another sector such as Portland Cement manufacturing.

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[18] Evaluation of Suitability of Selective Catalytic Reduction and Selective Non-Catalytic Reduction for use in Portland Cement Industry

[19] The Experience of SCR at Solnhofen and its Applicability to US Cement Plants, June 6, 2006. http://files.dep.state.pa.us/air/AirQuality/AQPortalFiles/Pollutants/transport/Comments/Lehigh_Attachment_Solnhofen.pdf

See Section 5.1.1 above for detailed discussion for the true cost of compliance. The cost summary spreadsheets for the NO_X emission control measures are provided in Appendix A for Line 1 Indurating Furnace and Appendix B for Line 2 Indurating Furnace.

The cost-effectiveness analysis compares the annualized cost of the technology 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 and consistent with the typical approach described in the EPA Control Cost Manual,[20] 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 Table 5-1.

Table 5-1: NO_X Control Cost Summary, per Unit Basis

Additional Emission Control Measure	Installed Capital Cost ($MM)	Annual Operating Costs ($/yr)	Annual Emissions Reduction (tpy)	Pollution Control Cost effectiveness ($/ton)
Line 1 - SCR with Reheat	$43,637,895	$21,350,897	662.5	$32,228
Line 2 - SCR with Reheat	$72,550,865	$41,336,088	937.0	$44,115

The cost-effectiveness value of SCR with reheat is substantially greater than the NO_X cost-effectiveness threshold determined in Section 4.2 of $1,193 to $2,800 per ton. Therefore, the costs for the SCR with reheat retrofit option is not reasonable.

Sections 5.3 through 5.5 provide a summary of the remaining three statutory factors evaluated for the NO_X emission control measures, understanding that these projects represent substantial capital investments that are not justified on a cost per ton or absolute cost basis.

5.3 Factor #2 – Time Necessary for Compliance

The amount of time needed for full implementation of the emission control measure varies. Typically, this includes the time needed to develop and approve the new emissions limit into the SIP by state and federal action, time for MPCA to modify UTAC’s Title V operating permit to allow construction to commence, then to implement the project necessary to meet the state SIP limit for the emission control measure, including capital funding, construction, tie-in to the process, commissioning, and performance testing.

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[20] US EPA, “EPA Air Pollution Control Cost Manual, Sixth Edition,” January 2002, EPA/452/B-02-001. The EPA has updated certain sections and chapters of the manual since January 2002. These individual sections and chapters may be accessed at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution as of the date of this report, page 2-26

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.

5.4 Factor #3 – Energy and Non-Air Quality Environmental Impacts of Compliance

The energy and non-air quality environmental impacts associated with the implementation of the above-identified NO_X control measure are summarized below.

5.4.1 Energy Impacts

As with all add-on controls, operation of an SCR system results in an increase in energy demand due to the pressure drop across the SCR catalyst. At a minimum, this would require increased electrical usage by the plant with an associated increase in indirect (secondary) emissions from nearby power stations. Electricity is required for the SCR equipment, to vaporize the aqueous ammonia reagent, and for additional fan power. Reheating the flue gas for SCR application would also require substantial natural gas usage with an associated increase in direct emissions. The cost of energy required to operate the control devices has been included in the cost analyses found in Appendix A and B.

5.4.2 Environmental Impacts

UTAC has considered air quality impacts for regional haze pollutants because they are directly applicable to the goals of this analysis. Overall, there are secondary air quality impacts associated with SCR operation, which diminish some of the benefits of the NO_X reductions. The associated increase in PM_{10} emissions will also increase the difficulty of obtaining a construction air permit (or potentially PSD) permit for the installation. MPCA should consider the increased emission of PM_{10}, SO_3, sulfuric acid mist, and ammonia in any visibility impact analyses associated with SCR installation.

Urea, which is decomposed in an external reactor to form ammonia, would be used in the SCR. The SCR system consists of an ammonia injection system and a catalytic reactor. Unreacted ammonia may escape through to the exhaust gas. This is commonly called “ammonia slip.” It is estimated that ammonia slip from an SCR on this size of furnace could be 2-10 ppm; this may be considered to be an environmental impact. The ammonia that is released may also react with other pollutants in the exhaust stream such as NO_X and SO_2 to create PM_{10} in the form of ammonium salts. The SCR catalysts must also be replaced on a routine basis. In some cases, these catalysts may be classified as hazardous waste. This typically requires either returning the material to the manufacturer for recycling and reuse or disposal in permitted landfills.

As previously noted in Section 5.2, the SCR would oxidize mercury resulting in an increase in local deposition of oxidized mercury emissions near the emission source and most certainly within northeast Minnesota. The TMDL study requires a reduction in loading in order to reduce fish tissue mercury concentrations.

Duct burners have adverse environmental impacts because they require additional fuel combustion to reheat the flue gas to the required oxidation temperatures. Therefore, the technology would have increased collateral air emissions (e.g. NO_X, CO, VOC, PM, GHG, etc.).

Additionally, there are safety concerns associated with the transport and storage of urea or ammonia, including potential spills that can have serious adverse health and environmental impacts.

5.5 Factor #4 – Remaining Useful Life of the Source

Because UTAC is assumed to continue operations for the foreseeable future, the useful life of the individual control measures (assumed 20-year life, per Section 4.5) is used to calculate emission reductions, amortized costs and cost-effectiveness on a dollar per ton basis.

5.6 NO_X Four-Factor Analysis Conclusion

Based on the analysis conducted in Sections 5.1 through 5.5, UTAC has determined that installation of additional NO_X emissions measures on the Line 1 and Line 2 Indurating Furnaces beyond those described in Section 3.1 are not feasible.

6 SO_2 Four-Factor Analysis

This section identifies and describes various SO_2 emission control measures, evaluates the four statutory factors for the Line 1 and Line 2 Indurating Furnaces, considers other factors, and determines if an emission control measure or measures are necessary to make reasonable progress. Consistent with EPA's guidance and MPCA direction, UTAC has completed a Four-Factor Analysis for SO_2 as described in Sections 6.1 to 6.6.

6.1 SO_2 Control Measures Overview

The SO_2 emissions occur as a result of the oxidation of sulfur that is present in the taconite ore and in the fuels combusted. In establishing the 2028 baseline emission rate, the lowest SO_2 concentration that can be reasonably achieved by add-on control technologies is 5 ppm. The 2028 baseline emission rate of 15.7 lb SO_2/hr for Line 1 equates to 4.9 ppm SO_2. The calculation of the equivalent SO_2 concentrations is provided in the cost summary spreadsheets for the SO_2 emission control measures in Appendices A and B. With a 2028 baseline SO_2 concentration of less than 5 ppm, the control technology control efficiency will result in negative values. This is an anomaly of the cost of control evaluation process. Therefore, all of the additional SO_2 control technology options for the Line 1 Indurating Furnace would not be considered feasible. The Four-Factor Analysis has therefore been performed for the Line 2 Indurating Furnace only. Table 6-1 lists the technically feasible SO_2 control technologies for the Line 2 Indurating Furnace.

Table 6-1 Additional SO_2 Control Measures with Potential Application at the Line 2 Indurating Furnace

Control Measures
DSI – New PM Control
SDA– New PM Control
GSA– New PM Control

As noted for each SO_2 control technology, new PM control equipment will be required to achieve the SO_2 control efficiencies and removal. The following describes pertinent technical information regarding each control measure and whether the control measure is technically feasible when applied to the Line 2 Indurating Furnace.

6.1.1 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.

6.1.2 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.

6.1.3 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.

6.2 Factor #1 – Cost of Compliance

UTAC has completed cost estimates for the selected SO_2 emission control measures. Cost summary spreadsheets for the SO_2 emission control measures are provided in Appendix B.

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,[20] 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 Table 6-2.

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

For Line 2 Indurating Furnace, the cost-effectiveness values for all of the SO_2 emission control measures are substantially greater than the cost-effectiveness threshold determined in Section 4.2 of $4,200 to $5,700 per ton. Therefore, the costs for the retrofit options are not reasonable.

Sections 6.3 through 6.5 provide a summary of the remaining three statutory factors evaluated for the SO_2 emission control measures, understanding that these projects represent substantial capital investments that are not justified on a cost per ton or absolute cost basis.

6.3 Factor #2 – Time Necessary for Compliance

The amount of time needed for full implementation of the emission control measure varies. Typically, this includes the time needed to develop and approve the new emissions limit into the SIP by state and federal action, time for MPCA to modify UTAC's Title V operating permit to allow construction to commence, then to implement the project necessary to meet the state SIP limit for the emission control measure, including capital funding, construction, tie-in to the process, commissioning, and performance testing.

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.

6.4 Factor #3 – Energy and Non-Air Quality Environmental Impacts of Compliance

The energy and non-air environmental impacts associated with implementation of the above identified SO_2 control measures are summarized below.

6.4.1 Energy Impacts

The SO_2 control technologies with new PM control would require additional electricity requirements. Similar to the NO_X add-on controls, operation of add-on SO_2 control systems with new PM control results in an increase in energy usage due to the higher pressure drop across the baghouse for all three technologies and pressure drop across the reactor for SDA and GSA technologies, material preparation such as grinding reagents, additional material handling equipment such as pumps and blowers, and steam requirements. Power consumption is also affected by reagent utilization, which also affects the control efficiency of the control technology. At a minimum, this would require increased electrical usage by the plant with an associated increase in indirect (secondary) emissions from nearby power stations. The cost of energy required to operate the control devices has been included in the cost analyses found in Appendix B.

6.4.2 Environmental Impacts

The DSI control technology would generate additional solid waste that would require disposal in permitted landfills. Currently, the collected solids in the wet scrubber is recirculated back into the process. With the removal of the wet scrubber and replacement with DSI control, the DSI reagent would directly mix with the process dust, rendering the dust unsuitable for recycling back into the process, and resulting in increased solids to the landfill as well as a loss in valuable iron units (i.e., decreased pellet production).

6.5 Factor #4 – Remaining Useful Life of the Source

Because UTAC is assumed to continue operations for the foreseeable future, the useful life of the individual control measures (assumed 20-year life, per Section 4.5) is used to calculate emission reductions, amortized costs and cost-effectiveness on a dollar per ton basis.

6.6 SO_2 Four-Factor Analysis Conclusion

Based on the analysis conducted in Sections 6.1 through 6.5, UTAC has determined that installation of additional SO_2 emission measures on the Line 1 and Line 2 Indurating Furnaces beyond those described in Section 3.1 are not feasible.

Appendix A

Unit-specific Screening Level Cost Summary for Line 1 Control Measures

Cleveland Cliffs: United Taconite Line 1
Appendix A - Four-Factor Control Cost Analysis
Table 1: Cost Summary

NO_x Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton
Selective Catalytic Reduction with Reheat (SCR)	50%	662.5	662.5	$43,637,895	$21,350,897	$32,228

Cleveland Cliffs: United Taconite Line 1
Appendix A - Four-Factor Control Cost Analysis
Table 2: Summary of Utility, Chemical and Supply Costs

Operating Unit:	Line 1	**Study Year**	2020
Emission Unit Number	EU 040		
Stack/Vent Number	SV 046		

Item	Unit Cost	Units	Cost	Year	Data Source	Notes
Operating Labor	72.12	$/hr		2020	Site-specific labor cost	
Maintenance Labor	72.12	$/hr		2020	Site-specific labor cost	
Electricity	0.068	$/kwh	68.44	2020	Site-specific cost	
Natural Gas	4.98	$/kscf		N/A	5-yr average based on natural gas prices (eia.gov)	
Water	0.01	$/kgal		2019	Site-specific cost from 2019	
Compressed Air	0.48	$/kscf	0.25	1998	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1	Adjusted for 3% inflation
Taconite Pellets	29.1	$/LT		2020	Based on Q1 2020 sales margin in earnings report	
Chemicals & Supplies						
Lime	183.68	$/ton	145.00	2012	Hydrated lime cost from 2012 Dry Flugas Desulfurization Study for UTAC Lines 1 and 2	Adjusted for 3% inflation
Urea 50% Solution	1.81	$/gallon	1.66	2017	EPA Control Cost Manual Chapter 7, 7th Edition default	Adjusted for 3% inflation
Trona	285.00	$/ton		2020	Vendor estimated delivered cost	
Estimated operating life of the SCR catalyst ($H_{catalyst}$)	8,000	hours			EPA Control Cost Manual Chapter 7, 7th Edition	
Catalyst cost ($CC_{replace}$)	248.05	$/cubic foot (inc	227	2017	EPA Control Cost Manual Chapter 7, 7th Edition default	Adjusted for 3% inflation
Cost per bag	116.70	$/bag	110	2018	Vendor estimated bag cost from the 2018 Best Available Mercury Reduction Technology (BAMRT) Analysis	Adjusted for 3% inflation
Other						
Sales Tax	6.875%	percent			Current MN sales tax rate	
Interest Rate	5.50%	percent			EPA Control Cost Manual Chapter 7, 7th Edition default	
Solid Waste Disposal	44.35	$/ton	41.8	2018	2018 site specific cost	Adjusted for 3% inflation
Contingency	10%	percent			EPA Control Cost Manual Chapter 2, 7th Edition estimates contingencies from 5-15%. Assumed the mid range	
Markup on capital cost (Retrofit Factor)	60%	percent			CUECost Workbook Version 1.0, USEPA Document Page 2 allows up to a 60% retrofit factor for installations in existing facilities.	
Operating Information						
Annual Op. Hrs	8376	Hours			Site-specific estimate	
Utilization Rate	100%	percent			Site-specific estimate	
Single Furnace Pellet Production Rate	250	Lton/hr			Furnace capacity	
Desgin Capacity	190	MMBTU/hr			Furnace capacity	
Equipment Life	20	yrs			Assumed	
Temperature- After Scrubber	140	Deg F			Stack test data	
Temperature- Before Scrubber	250	Deg F			Site-specific estimate	
Moisture Content-After Scrubber	13.7%				Stack test data	
Moisture Content-Before Scrubber	6.3%		1000	lb H2O/min	Site-specific estimate	
Existing Pollution Contols PM Inlet Concentraiton	2.17	gr/dscf dust load		2018	Site-specific estimate	
Existing Pollution Contols PM Control Efficiency	94%	percent			2020 TVOP reissuance application PM control efficiency	Efficiency is used to calculate the increased baghouse dust loading for DSI because the captured dust cannot be recycled to process with the spent/unreacted reagent. This does not apply to the GSA/SDA because there is an ESP upstream of the absorber.
Actual Flow Rate-After Scrubber	420,000	acfm			Site-specific estimate	
Actual Flow Rate-Before Scrubber	460,000	acfm			Site-specific estimate	
Standardized Flow Rate-After Scrubber	369,600	scfm @ 68º F	344,400	scfm @ 32º F	Calculated from stack temperature and flow data in acfm listed above	
Standardized Flow Rate-Before Scrubber	342,085	scfm @ 68º F	318,761	scfm @ 32º F	Calculated from stack temperature and flow data in acfm listed above	
Dry Std Flow Rate-After Scrubber	318,965	dscfm @ 68º F			Calculated from stack temperature and flow data in acfm listed above	
Dry Std Flow Rate-Before Scrubber	320,696	dscfm @ 68º F			Calculated from stack temperature and flow data in acfm listed above	
Fuel higher heating value (HHV)	1,033	BTU/scf			EPA Control Cost Manual Chapter 7, 7th Edition default	
Plant Elevation	1,500	Feet above sea level			Site elevation	
Method 19 Design Factor (SCR)	8,710	dscf/MMBtu			Natural gas F-Factor	
Technology Control Efficiencies						
SCR	50%	percent			Control efficiency provided by Solnhofer Portland Cement Works GmbH & Co. KG. Reference "The Experience of SCR at Solhhofen and its Applicability to US Cement Plants, June 6, 2006. According to Portland Cement Association, the EPA 7th Edition SCR control cost data severally underestimates the costs of installation and operation of SCR control technology designed for utility boilers and transfer to Portland Cement kilns. Assumed similar control efficiency to a cement kiln.	
GSA	-2%	percent			Calculated control efficiency to determine reduction over baseline emissions to 5 ppm outlet per vendor specifications	
SDA	-2%	percent			Calculated control efficiency to determine reduction over baseline emissions to 5 ppm outlet per vendor specifications	
DSI	-2%	percent			Calculated control efficiency to determine reduction over baseline emissions to 5 ppm outlet per vendor specifications. Note, it is unlikely that DSI can actually achieve 5 ppm SO2 outlet. However, to be conservative it was assume that this could be achieved.	
Existing scrubber SO2 Control Efficiency	25%	percent			Site-specific estimate	
	Baseline Emissions					
Pollutant	**lb/hr**	**tpy**	**ppmv**			
Nitrous Oxides (NOx)	348	1,325	151		Baseline tpy is site-specific estimate. Lb/hr represents average when furnace was operating at >50% capacity	
Sulfur Dioxide (SO2)	15.7	59.7	4.9		Baseline tpy is site-specific estimate. Lb/hr represents average when furnace was operating at >50% capacity	
Outlet SO2 controls target			5.0			
Sulfur Dioxide (SO2) Uncontrolled with Scrubbers Removed	20.9	79.6	7		SO2 emission rate without the existing scrubbers	

Cleveland Cliffs: United Taconite Line 1
Appendix A - Four-Factor Control Cost Analysis
Table 3: Selective Catalytic Reduction with Reheat

Operating Unit: **Line 1**

Emission Unit Number	EU 040		Stack/Vent Number	SV 046	
Design Capacity	190	MMBtu/hr	Standardized Flow Rate[5]	344,400	scfm @ 32º F
Expected Utilization Rate	100%		Exhaust Temperature[5]	140	Deg F
Expected Annual Hours of Operation	8,376	Hours	Exhaust Moisture Content[5]	13.7%	
Annual Interest Rate	5.5%		Actual Flow Rate[5]	420,000	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate[5]	369,600	scfm @ 68º F
Pellet Throughput	250	LTon/hr	Dry Std Flow Rate[5]	318,965	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Total Capital Investment (TCI) with Retrofit							SCR Only	42,558,186
							SCR + Reheat	**43,637,895**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.					SCR + Reheat	**17,578,490**
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost					SCR + Reheat	**3,772,408**
Total Annual Cost (Annualized Capital Cost + Operating Cost)							SCR + Reheat	**21,350,897**

Emission Control Cost Calculation

Pollutant	**Emissions Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrous Oxides (NOx)	348.0	1,325.0	50%	662.5	662.5	32,228

Notes & Assumptions

1 Estimated Equipment Cost per EPA Air Pollution Control Cost Manual 7th Ed SCR Control Cost Spreadsheet (June 2019)
2 TCI includes the cost of a new booster fan
3 For Calculation purposes, duty reflects increased flow rate, not actual duty.
4 CUECost Workbook Version 1.0, USEPA Document Page 2 allows up to a 60% retrofit factor for installations in existing facilities.
5 Specifications are after scrubber conditions.

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Table 3: Selective Catalytic Reduction with Reheat

CAPITAL COSTS

Total Capital Investment (TCI)		Refer to the *Cost Estimate* tab	**40,113,786**
Retrofit factor	60%	of TCI, see *Cost Estimate* tab	
Lost Production for Tie-In			2,444,400
Total Capital Investment Retrofit Installed			42,558,186

OPERATING COSTS

Direct Annual Operating Costs, DC

Maintenance			
Annual Maintenance Cost =		Refer to the *Cost Estimate* tab	197,727
Utilities, Supplies, Replacements & Waste Management			
Annual Electricity Cost =		Refer to the *Cost Estimate* tab	647,665
Annual Catalyst Replacement Cost =		Refer to the *Cost Estimate* tab	763,512
Annual Reagent Cost =		Refer to the *Cost Estimate* tab	381,769
Total Annual Direct Operating Costs			**1,990,673**

Indirect Operating Costs

Administrative Charges (AC) =		Refer to the *Cost Estimate* tab	5,393
Capital Recovery Costs (CR)=	0.0837	Refer to the *Cost Estimate* tab	3,562,120
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**3,567,513**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**5,558,186**

Cleveland Cliffs: United Taconite Line 1
Appendix A - Four-Factor Control Cost Analysis
Table 3: Selective Catalytic Reduction with Reheat

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catayst - Refer to the *Cost Estimate Tab*

Annualized Cost **$ 763,512**

Equivalent Duty	2,197
Uncontrolled Nox lb/mmBtu	0.158

SCR Capital Cost

Electrical Use

Reagent Use & Other Operating Costs
Refer to the *Cost Estimate* tab

Design Basis		**Max Emis** **lb/MMBtu**		**Control Eff (%)**
Nitrous Oxides (NOx)		0.158	Adjusted lb/MMBtu	50%
Actual	100,726	dscf/MMBtu		
Method 19 Factor	8,710	dscf/MMBtu	**NG F-FACTOR**	
Adjusted Duty	2,197	MMBtu/hr		

Operating Cost Calculations		
	Annual hours of operation:	**8,376**
	Utilization Rate:	**100%**

Refer to the *Cost Estimate* tab

Cleveland Cliffs: United Taconite Line 1
Appendix A - Four-Factor Control Cost Analysis
Table 4: Cost to Reheat Flue Gas (Duct Burner)

Operating Unit: **Line 1**

Emission Unit Number	EU 040		Stack/Vent Number	SV 046		**Chemical Engineering Chemical Plant Cost Index**	
	190	MMBtu/hr	Standardized Flow Rate[3]	344,400	scfm @ 32º F		
Expected Utilization Rate	100%		Exhaust Temperature[3]	140	Deg F	1998/1999	390
Expected Annual Hours of Operation	8,376	Hours	Exhaust Moisture Content[3]	13.7%		2019	607.5
Annual Interest Rate	5.5%		Actual Flow Rate[3]	420,000	acfm	Inflation Adj	1.56
Expected Equipment Life	20	yrs	Standardized Flow Rate[3]	369,600	scfm @ 68º F		
Pellet Throughput	250	LTon/hr	Dry Std Flow Rate[3]	318,965	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			329,582
Purchased Equipment Total (B)	22%	of control device cost (A)	**401,678**
Installation - Standard Costs	30%	of purchased equip cost (B)	120,503
Installation - Site Specific Costs			NA
Installation Total			120,503
Total Direct Capital Cost, DC			522,181
Total Indirect Capital Costs, IC	38%	of purchased equip cost (B)	152,637
Total Capital Investment (TCI) with Retrofit			**1,079,709**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	15,587,817
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	204,894
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**15,792,712**

Notes & Assumptions

1 Equipment cost estimate EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 3.2 Chapter 2.5.1
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 3.2 Chapter 2
3 Specifications are after scrubber conditions.

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Appendix A - Four-Factor Control Cost Analysis
Table 4: Cost to Reheat Flue Gas (Duct Burner)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**329,582**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	32,958
MN Sales Taxes	6.9%	of control device cost (A)	22,659
Freight	5%	of control device cost (A)	16,479
Purchased Equipment Total (B)	22%		**401,678**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	32,134
Handling & erection	14%	of purchased equip cost (B)	56,235
Electrical	4%	of purchased equip cost (B)	16,067
Piping	2%	of purchased equip cost (B)	8,034
Insulation	1%	of purchased equip cost (B)	4,017
Painting	1%	of purchased equip cost (B)	4,017
Installation Subtotal Standard Expenses	30%		**120,503**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			**120,503**
Total Direct Capital Cost, DC			**522,181**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	40,168
Construction & field expenses	5%	of purchased equip cost (B)	20,084
Contractor fees	10%	of purchased equip cost (B)	40,168
Start-up	2%	of purchased equip cost (B)	8,034
Performance test	1%	of purchased equip cost (B)	4,017
Model Studies		of purchased equip cost (B)	0
Contingencies	10%	of purchased equip cost (B)	40,168
Total Indirect Capital Costs, IC	38%	of purchased equip cost (B)	**152,637**
Total Capital Investment (TCI) = DC + IC			**674,818**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**674,818**
Total Capital Investment (TCI) with Retrofit Factor	60%	1.6 Retrofit Factor	**1,079,709**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	72.12	$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr	37,755
Supervisor	15%	15% of Operator Costs	5,663
Maintenance			
Maintenance Labor	72.12	$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr	37,755
Maintenance Materials	100%	of maintenance labor costs	37,755
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
Natural Gas	4.98	$/kscf, 6,181 scfm, 8376 hr/yr, 100% utilization	15,468,890
Total Annual Direct Operating Costs			**15,587,817**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	71,357
Administration (2% total capital costs)	2%	of total capital costs (TCI)	21,594
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	10,797
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	10,797
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	90,349
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**204,894**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**15,792,712**

Cleveland Cliffs: United Taconite Line 1
Appendix A - Four-Factor Control Cost Analysis
Table 4: Cost to Reheat Flue Gas (Duct Burner)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalyst:	**Catalyst**	
Equipment Life	3	years
CRF	0.3707	
Rep part cost per unit	0	$/ft^3
Amount Required	39	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	0	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr	OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use	Flow acfm		Δ P in H2O	Efficiency	Hp	kW	
Blower, Thermal	420,000		19	0.6		1,556.1	EPA Cost Cont Manual 6th ed - Oxidizders Chapter 2.5.2.1
Blower, Catalytic	420,000		23	0.6		1,883.7	EPA Cost Cont Manual 6th ed - Oxidizders Chapter 2.5.2.1
Oxidizer Type	**thermal**	(catalytic or thermal)				0.0	Reheat is by duct burner, pressure drop does not apply

Reagent Use & Other Operating Costs Oxidizers - NA

Operating Cost Calculations **Annual hours of operation:** **8,376**
Utilization Rate: **100%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	72.12	$/Hr	0.5	hr/8 hr shift	524	37,755	$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr
Supervisor	15%	of Op.			NA	5,663	15% of Operator Costs
Maintenance							
Maint Labor	72.12	$/Hr	0.5	hr/8 hr shift	524	37,755	$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	37,755	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.068	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 8376 hr/yr, 100% utilization
Natural Gas	4.98	$/kscf	6,181	scfm	3,106,203	15,468,890	$/kscf, 6,181 scfm, 8376 hr/yr, 100% utilization

*annual use rate is in same units of measurement as the unit cost factor

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Appendix A - Four-Factor Control Cost Analysis
Table 4: Cost to Reheat Flue Gas (Duct Burner)

Flue Gas Re-Heat Equipment Cost Estimate Basis Thermal Oxidizer with 70% Heat Recovery

Auxiliary Fuel Use Equation 3.19

T_{wi}	140	Deg F - Temperature of waste gas into heat recovery
T_{fi}	800	Deg F - Temperature of Flue gas into heat recovery
T_{ref}	77	Deg F - Reference temperature for fuel combustion calculations
FER	0%	Factional Heat Recovery % Heat recovery section efficiency
T_{wo}	140	Deg F - Temperature of waste gas out of heat recovery
T_{fo}	800	Deg F - Temperature of flue gas out of heat recovery
$-h_{caf}$	21502	Btu/lb Heat of combustion auxiliary fuel (methane)
$-h_{wg}$	0	Btu/lb Heat of combustion waste gas
$C_{p\ wg}$	0.2684	Btu/lb - Deg F Heat Capacity of waste gas (air)
p_{wg}	0.0739	lb/scf - Density of waste gas (air) at 77 Deg F
p_{af}	0.0408	lb/scf - Density of auxiliary fuel (methane) at 77 Deg F
Q_{wg}	369,600	scfm - Flow of waste gas
Q_{af}	6,181	scfm - Flow of auxiliary fuel

Cost Calculations	375,781	scfm Flue Gas	Cost in 1989 $'s	$211,583
			Current Cost Using CHE Plant Cost Index	$329,582

Heat Rec %	A	B	
0	10,294	0.2355	Exponents per equation 3.24
0.3	13,149	0.2609	Exponents per equation 3.25
0.5	17,056	0.2502	Exponents per equation 3.26
0.7	21,342	0.2500	Exponents per equation 3.27

Indurator Flue Gas Heat Capacity - Basis Typical Composition

		100 scfm		359 scf/lbmole			
		Gas Composition		lb/hr f	wt %	Cp Gas	Cp Flue
28	mw CO	0	v %	0			
44	mw CO2	15	v %	184	22.0%	0.24	0.0528
18	mw H2O	10	v %	50	6.0%	0.46	0.0276
28	mw N2	60	v %	468	56.0%	0.27	0.1512
32	mw O2	15	v %	134	16.0%	0.23	0.0368
	Cp Flue Gas	100	v %	836	100.0%		0.2684

Reference: OAQPS Control Cost Manual 5th Ed Feb 1996 - Chapter 3 Thermal & Catalytic Incinerators
(EPA 453/B-96-001)

Air Pollution Control Cost Estimation Spreadsheet
For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO_x emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO_x within a specific temperature range to produce N_2 and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 6). For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retrofit of an existing boiler. 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.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?	Industrial ▼
Is the SCR for a new boiler or retrofit of an existing boiler?	Retrofit ▼
What type of fuel does the unit burn?	Natural Gas ▼
Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.	1.6

* NOTE: You must document why a retrofit factor of 1.6 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	2,197	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,033	Btu/scf
What is the estimated actual annual fuel consumption?	17,816,081,913	
Operating hours	8,376	

*HHV value of 1033 Btu/scf is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

Enter the net plant heat input rate (NPHR)	8.2	MMBtu/MW

If the NPHR is not known, use the default NPHR value:

ASSUME DEFAULT

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation	1,500	Feet above sea level

coal burned: Not Applicable ▼

Enter the sulfur content (%S) =

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	
Bituminous Sub-Bituminous Lignite	

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

○ Method 1
○ Method 2
● Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	349	days
Number of days the boiler operates (t_{plant})	349	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.16	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.08	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	0.525	

*The SRF value of 0.525 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	2	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	882254	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	8,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	800	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	484	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	50	percent*
Density of reagent as stored (ρ_{stored})	71	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 50% and density of 71 lbs/cft are default values for urea reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used	Urea ▼

Enter the cost data for the proposed SCR:

Desired dollar-year	2019			
CEPCI for 2019	607.5	2019 final CEPCI value	541.7	2016 CEPCI
Annual Interest Rate (i)	5.5	Percent*		
Reagent ($Cost_{reag}$)	1.814	$/gallon for 50% urea		
Electricity ($Cost_{elect}$)	0.0684	$/kWh		
Catalyst cost ($CC_{replace}$)	248.05	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst		
Operator Labor Rate	72.12	$/hour (including benefits)		
Operator Hours/Day	4.00	hours/day*		

CEPCI = Chemical Engineering Plant Cost Index

* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)

* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) = 0.005

Administrative Charges Factor (ACF) = 0.03

1.325

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SCR Cost Development Methodology, Chapter 5, Attachment 5-3, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =			
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =			
Actual Annual fuel consumption (Mactual) =				
Heat Rate Factor (HRF) =	NPHR/10 =			
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =			
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =			
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =			
NOx removed per hour =	NOx_{in} x EF x Q_B =			
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =			
NO_x removal factor (NRF) =	EF/80 =			
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =			
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =			
Residence Time	1/V_{space}			
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^{6})/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =			
Retrofit Factor (RF)	Retrofit to existing boiler			

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer		
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})		
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)		
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)		

SCR Reactor Data:

Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$		
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$		
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft		

Reagent Data:

Type of reagent used

Molecular Weight of Reagent (MW) =

Density =

Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =		
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =		
	(m_{sol} x 7.4805)/Reagent Density		
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =		

Capital Recovery Factor:

Capital Recovery Factor (CRF) =	i $(1+ i)^{n}/(1+ i)^{n}$ - 1 = Where n = Equipment Life and i= Interest Rate	

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	1129.81	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$39,545,414	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,990,673	in 2019 dollars
Indirect Annual Costs (IDAC) =	$3,315,344	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$5,306,017	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$197,727	in 2019 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$381,769	in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$647,665	in 2019 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$763,512	in 2019 dollars
Direct Annual Cost =		$1,990,673	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$5,393	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$3,309,951	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$3,315,344	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$5,306,017	per year in 2019 dollars
NOx Removed =	663	tons/year
Cost Effectiveness =	$8,009.08	per ton of NOx removed in 2019 dollars

$/Ton above does not include reheat costs

Appendix B

Unit-specific Screening Level Cost Summary for Line 2 Control Measures

Cleveland Cliffs: United Taconite Line 2
Appendix B - Four-Factor Control Cost Analysis
Table 1: Cost Summary

NO_x Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton
Selective Catalytic Reduction with Reheat (SCR)	50%	937.0	937.0	$72,550,865	$41,336,088	$44,115

SO_2 Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton
Dry Sorbent Injection (DSI) with Baghouse	50%	107.2	108.2	$50,466,157	$10,090,749	$93,300
Spray Dry Absorber (SDA)	50%	107.2	108.2	$120,947,748	$19,573,967	$180,891
Gas Suspension Absorber (GSA)	50%	107.2	108.2	$113,793,152	$18,757,651	$173,347

Cleveland Cliffs: United Taconite Line 2
Appendix B - Four-Factor Control Cost Analysis
Table 2: Summary of Utility, Chemical and Supply Costs

Operating Unit:	Line 2
Emission Unit Number	EU 042
Stack/Vent Number	SV 048 & 049

Study Year 2020

Item	Unit Cost	Units	Cost	Year	Data Source	Notes
Operating Labor	72.12	$/hr		2020	Site-specific labor cost	
Maintenance Labor	72.12	$/hr		2020	Site-specific labor cost	
Electricity	0.068	$/kwh	68.44	2020	Site-specific cost	
Natural Gas	4.98	$/kscf		N/A	5-yr average based on natural gas prices (eia.gov)	
Water	0.01	$/kgal		2019	Site-specific cost from 2019	
Compressed Air	0.48	$/kscf	0.25	1998	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1	Adjusted for 3% inflation
Taconite Pellets	29.1	$/LT		2020	Based on Q1 2020 sales margin in earnings report	
Chemicals & Supplies						
Lime	183.68	$/ton	145.00	2012	Hydrated lime cost from 2012 Dry Flugas Desulfurization Study for UTAC Lines 1 and 2	Adjusted for 3% inflation
Urea 50% Solution	1.81	$/gallon	1.66	2017	EPA Control Cost Manual Chapter 7, 7th Edition default	Adjusted for 3% inflation
Trona	285.00	$/ton		2020	Vendor estimated delivered cost	
Estimated operating life of the catalyst ($H_{catalyst}$)	8,000	hours			EPA Control Cost Manual Chapter 7, 7th Edition	
Catalyst cost ($CC_{replace}$)	248.05	$/cubic foot (inclu	227	2017	EPA Control Cost Manual Chapter 7, 7th Edition default	Adjusted for 3% inflation
Cost per bag	116.70	$/bag	110	2018	Vendor estimated bag cost from the 2018 Best Available Mercury Reduction Technology (BAMRT) Analysis	Adjusted for 3% inflation
Other						
Sales Tax	6.875%	percent			Current MN sales tax rate	
Interest Rate	5.50%	percent			EPA Control Cost Manual Chapter 7, 7th Edition default	
Solid Waste Disposal	44.35	$/ton	41.8	2018	2018 site specific cost	Adjusted for 3% inflation
Contingency	10%	percent			EPA Control Cost Manual Chapter 2, 7th Edition estimates contingencies from 5-15%. Assumed the mid range	
Markup on capital cost (Retrofit Factor)	60%	percent			CUECost Workbook Version 1.0, USEPA Document Page 2 allows up to a 60% retrofit factor for installations in existing facilities. However, the retrofit factor does not apply to the GSA/SDA because the costs were based on a site-specific estimate.	
Operating Information						
Annual Op. Hrs	8376	Hours			Site-specific estimate	
Utilization Rate	100%				Site-specific estimate	
Single Furnace Pellet Production Rate	600	Lton/hr			Furnace capacity	
Desgin Capacity	400	MMBTU/hr			Furnace capacity	
Equipment Life	20	yrs			Assumed	
Temperature- After Scrubber	136	Deg F			Stack test data	
Temperature- Before Scrubber	300	Deg F			Site-specific estimate	
Moisture Content-After Scrubber	13.1%				Stack test data	
Moisture Content-Before Scrubber	6.3%		2300	lb h2o/min	Site-specific estimate	
Existing Pollution Contols PM Inlet Concentraiton	2.17	gr/dscf dust load		2018	Site-specific estimate	
Existing Pollution Contols PM Control Efficiency	94%	percent			2020 TVOP reissuance application PM control efficiency	Efficiency is used to calculate the increased baghouse dust loading for DSI because the captured dust cannot be recycled to process with the spent/unreacted reagent. This does not apply to the GSA/SDA because there is an ESP upstream of the absorber.
Actual Flow Rate-After Scrubber	840,000	acfm			Site-specific estimate	
Actual Flow Rate-Before Scrubber	1,120,210	acfm			Site-specific estimate	
Standardized Flow Rate-After Scrubber	744,161	scfm @ 68º F	693,423	scfm @ 32º F	Calculated from stack temperature and flow data in acfm listed above	
Standardized Flow Rate-Before Scrubber	778,251	scfm @ 68º F	725,189	scfm @ 32º F	Calculated from stack temperature and flow data in acfm listed above	
Dry Std Flow Rate-After Scrubber	646,676	dscfm @ 68º F			Calculated from stack temperature and flow data in acfm listed above	
Dry Std Flow Rate-Before Scrubber	729,057	dscfm @ 68º F			Calculated from stack temperature and flow data in acfm listed above	
Fuel higher heating value (HHV)	1,033	BTU/scf			EPA Control Cost Manual Chapter 7, 7th Edition default	
Plant Elevation	1,500	Feet above sea level			Site elevation	
Method 19 Design Factor (SCR)	8,710	dscf/MMBtu			Natural gas F-Factor	
Technology Control Efficiency						
SCR	50%	%			Control efficiency for a cement kiln referenced in the EPA Control Cost Manual Chapter 7, 7th Edition. Efficiencies may be as high as 90%, but SCR has not been demonstrated in practice on taconite indurating furnaces.	
GSA	50%	%			Calculated control efficiency to determine reduction over baseline emissions to 5 ppm outlet per vendor specifications	
SDA	50%	%			Calculated control efficiency to determine reduction over baseline emissions to 5 ppm outlet per vendor specifications	
DSI	50%	%			Calculated control efficiency to determine reduction over baseline emissions to 5 ppm outlet per vendor specifications. Note, it is unlikely that DSI can actually achieve 5 ppm SO2 outlet. However, to be conservative it was assume that this could be achieved.	
Existing scrubber SO2 Control Efficiency	25%	%			Site-specific estimate	
	Max Emis	**Baseline Emissions**				
Pollutant	**Lb/Hr**	**tpy**	**ppmv**			
Nitrous Oxides (NOx)	488.0	1,874.0	93		Baseline tpy is site-specific estimate. Lb/hr represents average during baseline period when furnace was operating at >50% capacity	
Sulfur Dioxide (SO2)	73.1	215.4	10		Baseline tpy is site-specific estimate. Lb/hr represents average during baseline period when furnace was operating at >50% capacity	
Outlet SO2 controls target			5			
Sulfur Dioxide (SO2) Uncontrolled with Scrubbers I	97.5	287.2	13		SO2 emission rate without the existing scrubbers	

Cleveland Cliffs: United Taconite Line 2
Appendix B - Four-Factor Control Cost Analysis
Table 3: NO$_x$ Control - Selective Catalytic Reduction with Reheat

Operating Unit: **Line 2**

Emission Unit Number	EU 042		Stack/Vent Number	SV 048 & 049	
Design Capacity	400	MMBtu/hr	Standardized Flow Rate[5]	693,423	scfm @ 32º F
Expected Utilization Rate	100%		Exhaust Temperature[5]	136	Deg F
Expected Annual Hours of Operation	8,376	Hours	Exhaust Moisture Content[5]	13.1%	
Annual Interest Rate	5.5%		Actual Flow Rate[5]	840,000	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate[5]	744,161	scfm @ 68º F
Pellet Throughput	600	LTon/hr	Dry Std Flow Rate[5]	646,676	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs									
Total Capital Investment (TCI) with Retrofit								SCR Only	71,277,677
								SCR + Reheat	**72,550,865**
Operating Costs									
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						SCR + Reheat	**35,153,534**
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						SCR + Reheat	**6,182,554**
Total Annual Cost (Annualized Capital Cost + Operating Cost)								SCR + Reheat	**41,336,088**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Nitrous Oxides (NOx)	488.0	1,874.0	50%	937.0	937.0	44,115

Notes & Assumptions

1 Estimated Equipment Cost per EPA Air Pollution Control Cost Manual 7th Ed SCR Control Cost Spreadsheet (June 2019)
2 TCI includes the cost of a new booster fan
3 For Calculation purposes, duty reflects increased flow rate, not actual duty.
4 CUECost Workbook Version 1.0, USEPA Document Page 2 allows up to a 60% retrofit factor for installations in existing facilities.
5 Specifications are after scrubber conditions.

Cleveland Cliffs: United Taconite Line 2
Appendix B - Four-Factor Control Cost Analysis
Table 3: NOx Control - Selective Catalytic Reduction with Reheat

CAPITAL COSTS

Total Capital Investment (TCI)		Refer to the *Cost Estimate* tab	**65,411,117**
Retrofit factor	60%	of TCI, see *Cost Estimate* tab	
Lost Production for Tie-In			5,866,560
Total Capital Investment Retrofit Installed			**71,277,677**

OPERATING COSTS

Direct Annual Operating Costs, DC			
Maintenance			
Annual Maintenance Cost =		Refer to the *Cost Estimate* tab	322,208
Utilities, Supplies, Replacements & Waste Management			
Annual Electricity Cost =		Refer to the *Cost Estimate* tab	1,313,090
Annual Catalyst Replacement Cost =		Refer to the *Cost Estimate* tab	1,523,872
Annual Reagent Cost =		Refer to the *Cost Estimate* tab	559,897
Total Annual Direct Operating Costs			**3,719,067**
Indirect Operating Costs			
Administrative Charges (AC) =		Refer to the *Cost Estimate* tab	6,887
Capital Recovery Costs (CR)=	0.0837	Refer to the *Cost Estimate* tab	5,965,942
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**5,972,828**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**9,691,896**

Cleveland Cliffs: United Taconite Line 2
Appendix B - Four-Factor Control Cost Analysis
Table 3: NOx Control - Selective Catalytic Reduction with Reheat

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catayst - Refer to the *Cost Estimate Tab*

Annualized Cost	$	**1,523,872**

Equivalent Duty	4,455
Uncontrolled Nox lb/mmBtu	0.115
SCR Capital Cost	

Electrical Use

Reagent Use & Other Operating Costs
Refer to the *Cost Estimate* tab

Design Basis		**Max Emis lb/MMBtu**		**Control Eff (%)**
				50%
Nitrous Oxides (NOx)		0.115	Adjusted lb/MMBtu	
Actual	97,001	dscf/MMBtu		
Method 19 Factor	8,710	dscf/MMBtu	**NG F-FACTOR**	
Adjusted Duty	4,455	MMBtu/hr		

Operating Cost Calculations		
	Annual hours of operation:	**8,376**
	Utilization Rate:	**100%**

Refer to the *Cost Estimate* tab

Cleveland Cliffs: United Taconite Line 2
Appendix B - Four-Factor Control Cost Analysis
Table 4: Cost to Reheat Flue Gas (Duct Burner)

Operating Unit: **Line 2**

Emission Unit Number	EU 042		Stack/Vent Number	SV 048 & 049		**Chemical Engineering Chemical Plant Cost Index**	
	400	MMBtu/hr	Standardized Flow Rate[3]	693,423	scfm @ 32º F		
Expected Utilization Rate	100%		Exhaust Temperature[3]	136	Deg F	1998/1999	390
Expected Annual Hours of Operation	8,376	Hours	Exhaust Moisture Content[3]	13.1%		2019	607.5
Annual Interest Rate	5.5%		Actual Flow Rate[3]	840,000	acfm	Inflation Adj	1.56
Expected Equipment Life	20	yrs	Standardized Flow Rate[3]	744,161	scfm @ 68º F		
Pellet Throughput	600	LTon/hr	Dry Std Flow Rate[3]	646,676	dscfm @ 68º F		

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			388,641
Purchased Equipment Total (B)	22%	of control device cost (A)	**473,656**
Installation - Standard Costs	30%	of purchased equip cost (B)	142,097
Installation - Site Specific Costs			NA
Installation Total			142,097
Total Direct Capital Cost, DC			615,753
Total Indirect Capital Costs, IC	38%	of purchased equip cost (B)	179,989
Total Capital Investment (TCI) with Retrofit			**1,273,188**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	31,434,467
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	209,726
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**31,644,192**

Notes & Assumptions

1 Equipment cost estimate EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 3.2 Chapter 2.5.1
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 3.2 Chapter 2
3 Specifications are after scrubber conditions.

Cleveland Cliffs: United Taconite Line 2
Appendix B - Four-Factor Control Cost Analysis
Table 4: Cost to Reheat Flue Gas (Duct Burner)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**388,641**
Purchased Equipment Costs (A) - Absorber + packing + auxillary equipment, EC			
Instrumentation	10%	of control device cost (A)	38,864
MN Sales Taxes	6.9%	of control device cost (A)	26,719
Freight	5%	of control device cost (A)	19,432
Purchased Equipment Total (B)	22%		**473,656**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	37,893
Handling & erection	14%	of purchased equip cost (B)	66,312
Electrical	4%	of purchased equip cost (B)	18,946
Piping	2%	of purchased equip cost (B)	9,473
Insulation	1%	of purchased equip cost (B)	4,737
Painting	1%	of purchased equip cost (B)	4,737
Installation Subtotal Standard Expenses	30%		**142,097**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			**142,097**
Total Direct Capital Cost, DC			**615,753**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	47,366
Construction & field expenses	5%	of purchased equip cost (B)	23,683
Contractor fees	10%	of purchased equip cost (B)	47,366
Start-up	2%	of purchased equip cost (B)	9,473
Performance test	1%	of purchased equip cost (B)	4,737
Model Studies		of purchased equip cost (B)	0
Contingencies	10%	of purchased equip cost (B)	47,366
Total Indirect Capital Costs, IC	38%	of purchased equip cost (B)	**179,989**
Total Capital Investment (TCI) = DC + IC			**795,743**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**795,743**
Total Capital Investment (TCI) with Retrofit Factor	60%	1.6 Retrofit Factor	**1,273,188**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	72.12	$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr	37,755
Supervisor	15%	15% of Operator Costs	5,663
Maintenance			
Maintenance Labor	72.12	$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr	37,755
Maintenance Materials	100%	of maintenance labor costs	37,755
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
Natural Gas	4.98	$/kscf, 12,512 scfm, 8376 hr/yr, 100% utilization	31,315,539
Total Annual Direct Operating Costs			**31,434,467**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	71,357
Administration (2% total capital costs)	2%	of total capital costs (TCI)	15,915
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	7,957
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	7,957
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	106,540
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**209,726**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**31,644,192**

Cleveland Cliffs: United Taconite Line 2
Appendix B - Four-Factor Control Cost Analysis
Table 4: Cost to Reheat Flue Gas (Duct Burner)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalyst:	**Catalyst**	
Equipment Life	3	years
CRF	0.3707	
Rep part cost per unit	0	$\$/\text{ft}^3$
Amount Required	39	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	0	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr	OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use	Flow acfm		Δ P in H2O	Efficiency	Hp	kW	
Blower, Thermal	840,000		19	0.6		3,112.2	EPA Cost Cont Manual 6th ed - Oxidizders Chapter 2.5.2.1
Blower, Catalytic	840,000		23	0.6		3,767.4	EPA Cost Cont Manual 6th ed - Oxidizders Chapter 2.5.2.1
Oxidizer Type	**thermal**	(catalytic or thermal)				0.0	Reheat is by duct burner, pressure drop does not apply

Reagent Use & Other Operating Costs Oxidizers - NA

Operating Cost Calculations **Annual hours of operation:** **8,376**
Utilization Rate: **100%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	72.12	$/Hr	0.5	hr/8 hr shift	524	37,755	$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr
Supervisor	15%	of Op.			NA	5,663	15% of Operator Costs
Maintenance							
Maint Labor	72.12	$/Hr	0.5	hr/8 hr shift	524	37,755	$/Hr, 0.5 hr/8 hr shift, 8376 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	37,755	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.068	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 8376 hr/yr, 100% utilization
Natural Gas	4.98	$/kscf	12,512	scfm	6,288,261	31,315,539	$/kscf, 12,512 scfm, 8376 hr/yr, 100% utilization

*annual use rate is in same units of measurement as the unit cost factor

Cleveland Cliffs: United Taconite Line 2
Appendix B - Four-Factor Control Cost Analysis
Table 4: Cost to Reheat Flue Gas (Duct Burner)

Flue Gas Re-Heat Equipment Cost Estimate Basis Thermal Oxidizer with 70% Heat Recovery

Auxiliary Fuel Use Equation 3.19

T_{wi}	136	Deg F - Temperature of waste gas into heat recovery
T_{fi}	800	Deg F - Temperature of Flue gas into heat recovery
T_{ref}	77	Deg F - Reference temperature for fuel combustion calculations
FER	0%	Factional Heat Recovery % Heat recovery section efficiency
T_{wo}	136	Deg F - Temperature of waste gas out of heat recovery
T_{fo}	800	Deg F - Temperature of flue gas out of heat recovery
$-h_{caf}$	21502	Btu/lb Heat of combustion auxiliary fuel (methane)
$-h_{wg}$	0	Btu/lb Heat of combustion waste gas
$C_{p\ wg}$	0.2684	Btu/lb - Deg F Heat Capacity of waste gas (air)
p_{wg}	0.0739	lb/scf - Density of waste gas (air) at 77 Deg F
p_{af}	0.0408	lb/scf - Density of auxiliary fuel (methane) at 77 Deg F
Q_{wg}	744,161	scfm - Flow of waste gas
Q_{af}	12,512	scfm - Flow of auxiliary fuel

Cost Calculations   756,674 scfm Flue Gas   Cost in 1989 $'s $249,498

Current Cost Using CHE Plant Cost Index $388,641

Heat Rec %	A	B	
0	10,294	0.2355	Exponents per equation 3.24
0.3	13,149	0.2609	Exponents per equation 3.25
0.5	17,056	0.2502	Exponents per equation 3.26
0.7	21,342	0.2500	Exponents per equation 3.27

Indurator Flue Gas Heat Capacity - Basis Typical Composition

100 scfm   359 scf/lbmole

		Gas Composition		lb/hr f	wt %	Cp Gas	Cp Flue
28	mw CO	0	v %	0			
44	mw CO2	15	v %	184	22.0%	0.24	0.0528
18	mw H2O	10	v %	50	6.0%	0.46	0.0276
28	mw N2	60	v %	468	56.0%	0.27	0.1512
32	mw O2	15	v %	134	16.0%	0.23	0.0368
	Cp Flue Gas	100	v %	836	100.0%		0.2684

Reference: OAQPS Control Cost Manual 5th Ed Feb 1996 - Chapter 3 Thermal & Catalytic Incinerators (EPA 453/B-96-001)

Air Pollution Control Cost Estimation Spreadsheet
For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO_x emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO_x within a specific temperature range to produce N_2 and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 6). For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retrofit of an existing boiler. 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.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

What type of fuel does the unit burn? Natural Gas

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.6

Do not rename this tab - EPA CCM spreadsheet has hidden

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 4,455 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,033 Btu/scf

*HHV value of 1033 Btu/scf is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual fuel consumption? 36,120,700,808

Operating Hours 8,376

Enter the net plant heat input rate (NPHR) 8.2 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

ASSUME DEFAULT

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 1,500 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

○ Method 1
○ Method 2
● Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	349	days
Number of days the boiler operates (t_{plant})	349	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.11	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.057	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	0.525	

*The SRF value of 0.525 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	2	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	1776357	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	8,000	hours
Estimated SCR equipment life	20	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	800	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	484	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	50	percent*
Density of reagent as stored (ρ_{stored})	71	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 50% and density of 71 lbs/cft are default values for urea reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used: Urea ▼

Enter the cost data for the proposed SCR:

Desired dollar-year	2019			
CEPCI for 2019	607.5	2019 final CEPCI value	541.7	2016 CEPCI
Annual Interest Rate (i)	5.5	Percent*		
Reagent ($Cost_{reag}$)	1.814	$/gallon for 50% urea		
Electricity ($Cost_{elect}$)	0.0684	$/kWh		
Catalyst cost ($CC_{replace}$)	248.05	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst		
Operator Labor Rate	72.12	$/hour (including benefits)		
Operator Hours/Day	4.00	hours/day*		

CEPCI = Chemical Engineering Plant Cost Index

* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)

* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005	1.325
Administrative Charges Factor (ACF) =	0.03	

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SCR Cost Development Methodology, Chapter 5, Attachment 5-3, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =			
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =			
Actual Annual fuel consumption (Mactual) =				
Heat Rate Factor (HRF) =	NPHR/10 =			
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =			
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =			
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =			
NOx removed per hour =	NOx_{in} x EF x Q_B =			
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =			
NO_x removal factor (NRF) =	EF/80 =			
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =			
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =			
Residence Time	1/V_{space}			
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =			
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =			
Retrofit Factor (RF)	Retrofit to existing boiler			

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer		
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})		
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)		
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)		

SCR Reactor Data:

Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$		
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$		
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft		

Reagent Data:

Type of reagent used

Molecular Weight of Reagent (MW) =

Density =

Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =		
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =		
	(m_{sol} x 7.4805)/Reagent Density		
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =		

Capital Recovery Factor:

Capital Recovery Factor (CRF) =	i $(1+ i)^n$/$(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	2290.59	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$64,441,596	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$3,719,067	in 2019 dollars
Indirect Annual Costs (IDAC) =	$5,400,648	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$9,119,716	in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$322,208	in 2019 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$559,897	in 2019 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$1,313,090	in 2019 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$1,523,872	in 2019 dollars
Direct Annual Cost =		$3,719,067	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$6,887	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$5,393,762	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$5,400,648	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$9,119,716	per year in 2019 dollars
NOx Removed =	937	tons/year
Cost Effectiveness =	$9,732.89	per ton of NOx removed in 2019 dollars

$/Ton above does not include reheat costs

Cleveland Cliffs: United Taconite Line 2
Appendix B - Four-Factor Control Cost Analysis
Table 5: Control Dry Sorbent Injection (DSI) with Baghouse

Operating Unit: **Line 2**

Emission Unit Number	EU 042		Stack/Vent Number	SV 048 & 049	
Design Capacity	400	MMBtu/hr	Standardized Flow Rate	725,189	scfm @ 32º F
Utilization Rate	100%		Exhaust Temperature	300	Deg F
Annual Operating Hours	8,376	Hours	Exhaust Moisture Content	6.3%	
Annual Interest Rate	5.50%		Actual Flow Rate	1,120,210	acfm
Control Equipment Life	20	yrs	Standardized Flow Rate	778,251	scfm @ 68º F
Pellet Throughput	600	LTon/hr	Dry Std Flow Rate	729,057	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs									
Direct Capital Costs									
Purchased Equipment (A)									**9,551,151**
Purchased Equipment Total (B)	12%	of control device cost (A)							**10,685,351**
Installation - Standard Costs	70%	of purchased equip cost (B)							7,479,745
Installation - Site Specific Costs									11,318,403
Installation Total									18,798,149
Total Direct Capital Cost, DC									29,483,499
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)							5,556,382
Total Capital Investment (TCI) = DC + IC									**33,741,308**
Total Capital Investment (TCI) with Retrofit Factor									**50,466,157**
Operating Costs									
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.							4,657,379
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost							6,740,531
Total Annual Cost (Annualized Capital Cost + Operating Cost)									**10,090,749**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual Ton/Yr**	**Calculation Method**	**Cont Eff %**	**Performance Basis**	**Conc. Units**	**Cont Emis Ton/Yr**	**Reduction Ton/Yr**	**Cont Cost $/Ton Rem**
PM10									
PM2.5									
Total Particulates									
Nitrous Oxides (NOx)									
Sulfur Dioxide (SO2)	73.13	215.40	% Removal	50%	NA	NA	107.19	108.21	$93,300
Sulfuric Acid Mist (H2SO4)									
Fluorides									
Volatile Organic Compounds (VOC)									
Carbon Monoxide (CO)									
Lead (Pb)									

Notes & Assumptions

1 Purchased equipment cost from vendor quotes for baghouse and anciliary equipment, adjusted for inflation using the Chemical Engineering Plant Cost Index (CEPCI).
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1
3 Used 0.6 power law factor to adjust prices based on acfm from vendor bids if applicable
4 Trona DSI applications typically achieve a 70% SO2 reduction, but the uncontrolled concentrations are too low to achieve this level of control
5 Electricity demand is the incremental cost for additional power demand with the removal of the existing particulate controls

Cleveland Cliffs: United Taconite Line 2
Appendix B - Four-Factor Control Cost Analysis
Table 5: Control Dry Sorbent Injection (DSI) with Baghouse

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**9,551,151**
Purchased Equipment Costs (A) - Injection System + auxiliary equipment, EC			
Instrumentation	0%	Included in vendor estimate	-
State Sales Taxes	6.9%	of control device cost (A)	656,642
Freight	5%	of control device cost (A)	477,558
Purchased Equipment Total (B)	12%		**10,685,351**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	427,414
Handling & erection	50%	of purchased equip cost (B)	5,342,675
Electrical	8%	of purchased equip cost (B)	854,828
Piping	1%	of purchased equip cost (B)	106,854
Insulation	7%	of purchased equip cost (B)	747,975
Painting	0%	Included in vendor estimate	-
Installation Subtotal Standard Expenses	70%		**7,479,745**
Site specific - Site Prep	N/A	Site Specific	94,293
Site specific - Ductwork	N/A	Site Specific	3,198,081
Site specific - Buildings	N/A	Site Specific	2,159,470
0	N/A	Site Specific	0
Lost Production for Tie-In	N/A	Site Specific	5,866,560
Total Site Specific Costs			11,318,403
Installation Total			**18,798,149**
Total Direct Capital Cost, DC			**29,483,499**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	1,068,535
Construction & field expenses	20%	of purchased equip cost (B)	2,137,070
Contractor fees	10%	of purchased equip cost (B)	1,068,535
Start-up	1%	of purchased equip cost (B)	106,854
Performance test	1%	of purchased equip cost (B)	106,854
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	1,068,535
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**5,556,382**
Total Capital Investment (TCI) = DC + IC			**35,039,882**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**33,741,308**
Total Capital Investment (TCI) with Retrofit Factor	60%	1.6 Retrofit Factor	**50,466,157**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	72.12	$/Hr	151,019
Supervisor	0.15	of Op Labor	22,653
Maintenance			
Maintenance Labor	72.12	$/Hr	75,510
Maintenance Materials	100	% of Maintenance Labor	75,510
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.07	$/kwh	1,062,948
Solid Waste Disposal	44.35	$/ton	2,436,978
Trona	285.00	$/ton	578,973
Taconite Product Loss	29	$/LTon	253,788
Total Annual Direct Operating Costs			**4,657,379**
Savings from Shutdown of Existing Emission Controls			**$ (1,307,161)**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	194,815
Administration (2% total capital costs)	2%	of total capital costs (TCI)	1,009,323
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	504,662
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	504,662
Capital Recovery	0.0837	for a 20-year equipment life and a 5.5% interest rate	4,222,974
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery costs	**6,740,531**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**10,090,749**

Cleveland Cliffs: United Taconite Line 2
Appendix B - Four-Factor Control Cost Analysis
Table 5: Control Dry Sorbent Injection (DSI) with Baghouse

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:	**Filter Bags**	
Equipment Life	5	years
CRF	0.2342	
Rep part cost per unit	117	$/bag
Amount Required	8399	Bags
Total Rep Parts Cost	1,096,651	Cost adjusted for freight & sales tax
Installation Labor	201,923	20 min per bag
Total Installed Cost	**1,298,573**	
Annualized Cost	**304,095**	

Electrical Use

	Flow acfm	D P in H2O	kWhr/yr	
Blower	1,120,210	7.18	12,199,907	Incremental electricity increase over with baghouse replacing scrubber including ducting
Air Compressor			3,331,191	Based on Compressor HP
Total			15,531,098	

Reagent Use & Other Operating Costs

Trona use - 1.5 NSR	73.13	lb/hr SO2	485.07	lb/hr Trona
Solid Waste Disposal	53,322	ton/yr existing scrubber inlet process dust loading		
Solid Waste Disposal	1,632	ton/yr DSI unreacted sorbent and reaction byproducts		
Taconite Product Loss	8721	ton/yr lost iron production from scrubber replacement by baghouse		

Operating Cost Calculations

Utilization Rate 100% Annual Operating Hours 8,376

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***		**Annual Cost**	**Comments**
Operating Labor								
Op Labor	72.12	$/Hr	2.0	hr/8 hr shift	2,094	$	151,019	$/Hr, 2.0 hr/8 hr shift, 2,094 hr/yr
Supervisor	15%	of Op Labor			NA	$	22,653	% of Operator Costs
Maintenance								
Maint Labor	72.12	$/Hr	1.0	hr/8 hr shift	1,047	$	75,510	$/Hr, 1.0 hr/8 hr shift, 1,047 hr/yr
Maint Mtls	100%	of Maintenance Labor			NA	$	75,510	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management								
Electricity	0.068	$/kwh	1854.2	kW-hr	15,531,098	$	1,062,948	$/kwh, 1,854 kW-hr, 8376 hr/yr, 100% utilization
Solid Waste Disposal	44.35	$/ton	6.56	ton/hr	54,954	$	2,436,978	$/ton, 7 ton/hr, 8376 hr/yr, 100% utilization
Trona	285.00	$/ton	485.1	lb/hr	2,031	$	578,973	$/ton, 485 lb/hr, 8376 hr/yr, 100% utilization
Taconite Pellets	29.100	$/LTon	1.0	LT/hr	8,721	$	253,788	$/LTon, 1 LT/hr, 8376 hr/yr, 100% utilization

Cleveland Cliffs: United Taconite Line 2
Appendix B - Four-Factor Control Cost Analysis
Table 6 - Spray Dry Absorber (SDA)

Operating Unit: **Line 2**

Emission Unit Number	EU 042		Stack/Vent Number	SV 048 & 049	
Expected Utilization Rate	100%		Temperature	300	Deg F
Expected Annual Hours of Operation	8,376	Hours	Moisture Content	6.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	1,120,210	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	778,251	scfm @ 68º F
Pellet Throughput	600	LTon/hr	Dry Std Flow Rate	729,057	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								26,325,693
Purchased Equipment Total (B)	10%	of control device cost (A)						**28,958,262**
Installation - Standard Costs	74%	of purchased equip cost (B)						21,429,114
Installation - Site Specific Costs								59,029,538
Installation Total								21,429,114
Total Direct Capital Cost, DC								50,387,376
Total Indirect Capital Costs, IC	42%	of purchased equip cost (B)						12,162,470
Total Capital Investment (TCI) with Site-specific Costs								**120,947,748**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						5,410,769
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						15,470,358
Savings from Shutdown of Existing Emission Controls								(1,307,161)
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**19,573,967**

Emission Control Cost Calculation

		Actual Emissions						
Pollutant	**Max Emis lb/hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc.**	**Conc. Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Sulfur Dioxide (SO_2):	51.4	215	50.2%	5	ppm	107.2	108	$180,891

Notes & Assumptions

1 Purchased equipment costs from independent review by Zachry Engineering scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)

2 Capital equipment cost includes the items listed below, which are calculated using EPA cost control manual guidance.

3 GSA/SDA designed for 5 ppm exit SO2 concentration

4 6/18/2012 email from Candice Maxwell, Cleveland Cliffs in response to EPA Region 5 CAA Section 114 information request for scrubber operating costs. Email reported total annual operating costs for both Scrubbers. Listed value excludes capital recover costs and is pro-rated by scrubber exhaust flow rate. Value includes continuing operations cost, per a 9/26/12 e-mail from Jen Krause, Cleveland Cliffs.

5 CUECost Workbook Version 1.0, USEPA Document Page 2 allows up to a 60% retrofit factor for installations in existing facilities

6 Site specific installation costs from independent review by Zachry Engineering.

7 Labor required for handling of lime shipments entering and exiting the facility. Includes spill prevention/cleanup and truck cleaning.

8 Determined from Table 3.21 of Chapter 3 of EPA's September 1999 Particulate Matter control design guidelines (for ESPs)

9 Labor and maintenance materials are 5% of capital costs per CueCost. "Average process with normal operating conditions should have maintenance labor and material costs" of 5 to 9% of fixed capital investment. (page 134, Plant Design and Economics for Chemical Engineers, Max Peters and Klaus Timmerhaus; McGraw-Hill Book Company)

10 Determined from Table 1.11 of Chapter 1 of EPA's December 1998 Particulate Matter control design guidelines (for FFs and baghouses)

11 Contingency is accounted for under Site Specific Installed Equipment Costs.

Cleveland Cliffs: United Taconite Line 2
Appendix B - Four-Factor Control Cost Analysis
Table 6 - Spray Dry Absorber (SDA)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A)			
Purchased Equipment Costs (A)			**26,325,693**
Instrumentation	10%	of control device cost (A)	2,632,569
MN Sales Taxes	0%	of control device cost (A)	0
Freight	0%	of control device cost (A)	0
Purchased Equipment Total (B)	10%		**28,958,262**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	1,158,330
Handling & erection	50%	of purchased equip cost (B)	14,479,131
Electrical	8%	of purchased equip cost (B)	2,316,661
Piping	1%	of purchased equip cost (B)	289,583
Insulation	7%	of purchased equip cost (B)	2,027,078
Painting	4%	of purchased equip cost (B)	1,158,330
Installation Subtotal Standard Expenses	74%		**21,429,114**
Total Direct Capital Cost, DC			**50,387,376**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	2,895,826
Construction & field expenses	20%	of purchased equip cost (B)	5,791,652
Contractor fees	10%	of purchased equip cost (B)	2,895,826
Start-up	1%	of purchased equip cost (B)	289,583
Performance test	1%	of purchased equip cost (B)	289,583
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	0%	of purchased equip cost (B)	0
Total Indirect Capital Costs, IC	42%	of purchased equip cost (B)	**12,162,470**
Total Capital Investment (TCI) = DC + IC			**62,549,846**
TCI Adj for Baghouse Filter Replacement			**61,918,209**
Retrofit multiplier	0%	of TCI	**0**
Site Specific Installed Equipment Costs			
Civil/Structural			1,664,454
Mechanical Equipment			36,936,333
Electrical and Control			4,839,425
Freight			1,350,994
Total Indirect Costs + Contingencies			8,371,773
Lost Production for Tie-In	N/A	Site Specific	5,866,560
Total Site Specific Costs			**59,029,538**
Total Capital Investment (TCI) Retrofit Installed			**120,947,748**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	72.12	$/Hr, 5.0 hr/8 hr shift, Annual Operating Hours	427,551
Supervisor	15%	15% of Operator Costs	64,133
Maintenance			
Maintenance Labor	72.12	$/hr, Maint Labor Use Rate+ESP Maint Labor Use Rate	75,510
Maintenance Materials	100%	of maintenance labor costs + 1% ESP purchase cost	285,510
Utilities, Supplies, Replacements & Waste Management			
Compressed Air	$ 0.48	$/kscf	539,357
Electricity	0.07	$/kwh, 6,435 kW-hr, annual operating hours, 100% utilization	3,688,680
Filter Bag Replacement			234,119
Solid Waste Disposal	44.35	$/ton, 136 lb/hr, annual operating hours, 100% utilization	25,228
Lime	183.68	$/ton, 92 lb/hr, annual operating hours, 100% utilization	70,682
Total Annual Direct Operating Costs			**5,410,769**
Savings from Shutdown of Existing Emission Controls			**(1,307,161)**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	511,622
Administration (2% total capital costs)	2%	of total capital costs (TCI)	2,418,955
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	1,209,477
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	1,209,477
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	10,120,827
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**15,470,358**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**19,573,967**

See Summary page for notes and assumptions

Cleveland Cliffs: United Taconite Line 2
Appendix B - Four-Factor Control Cost Analysis
Table 6 - Spray Dry Absorber (SDA)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalyst:		
Equipment Life	20	years
CRF	0.0000	
Rep part cost per unit	0	$\$/\text{ft}^3$
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment: Filter Bags and Cages			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	116.70	$ each	Price of 1 bag plus 1/2 price of 1 cage, from Zachry.
Amount Required	4488	Number	Number of bags, from Ducon proposal.
Total Rep Parts Cost	523,745	Cost adjusted for freight & sales tax	
Installation Labor	107,892		OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost	**631,637**	**Zero out if no replacement parts needed**	
Annualized Cost	**234,119**		

Electrical Use							
	Flow acfm		**Δ P in H_2O**	**Efficiency**	**Hp**	**kW**	
Process ID Fan	-		-	-	1,500.0	1,125.0	Fan size from Zachry cost estimates.
Process ID Fan	-		-	-	1,500.0	1,125.0	Fan size from Zachry cost estimates.
Process Booster Fan	-		-	-	2,500.0	1,875.0	Fan size from Zachry cost estimates.
Process Booster Fan	-		-	-	2,500.0	1,875.0	Fan size from Zachry cost estimates.
	Flow	**Liquid SPGR**	**Δ P ft H_2O**	**Efficiency**	**Hp**	**kW**	
Circ Pump	000 gpm	1	60	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H_2O WW Disch	0 gpm	1	60	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
		SCA[1] **ft^2/kacfm**	**Plate Area** **ft^2**	**kW/ft^2**			
ESP Power		200	224,042	1.94E-03		434.6	EPA Cont Cost Manual 6th ed - Sec 6 Ch 3 Eq 3.48
Other							
Total						6434.6	

Reagent Use & Other Operating Costs				
Hydrated Lime Use	51.43	lb/hr SO_2 no scrubber	91.88	lb/hr lime, lime addition
NSR	1.30		114.63	lb $CaSO_3$/hr
Waste Lime			21.20	lb/hr waste lime
Total Waste			135.84	lb/hr waste

An NSR of 1.3 means that 30% more lime is injected than is needed to capture SO_2.

Operating Cost Calculations — **Annual hours of operation:** **8,376**; **Utilization Rate:** **100%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor BH + ESP	72.12	$/Hr	5.0	hr/8 hr shift	5,235	377,548	$/Hr, 5.0 hr/8 hr shift, Annual Operating Hours
Lime Handling Labor	72.12	$/Hr	13.3	hr/week	693.3	50,003	$/Hr, 13.3 hr/week, Annual Operating Hours
Supervisor	15%	of Op.			NA	64,133	15% of Operator Costs
Maintenance							
Maint Labor Baghouse	72.12	$/Hr	1.0	hr/8 hr shift	1,047	75,510	$/Hr, 1.0 hr/8 hr shift, Annual Operating Hours
Maint Mtls Baghouse	100	% of Maintenance Labor			NA	75,510	100% of Maintenance Labor
ESP Maint Mtls and Lbr	5	% of ESP purchase cost				210,000	5% of ESP Purchase Cost
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.068	$/kwh	6434.6	kW-hr	53,896,557	3,688,680	$/kwh, 6,435 kW-hr, annual operating hours, 100% utilization
Water	0.01	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, annual operating hours, 100% utilization
Solid Waste Disposal	44.35	$/ton	135.8	lb/hr	569	25,228	$/ton, 136 lb/hr, annual operating hours, 100% utilization
Lime	183.7	$/ton	91.9	lb/hr	385	70,682	$/ton, 92 lb/hr, annual operating hours, 100% utilization
Filter Bag Replacement						234,119	2012 Dry FGD Study - Opinion of Probable Cost O&M Costs
Compressed Air	$ 0.48	$/kscf	2	scfm/kacfm	1,125,945	539,357	$/yr

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

Cleveland Cliffs: United Taconite Line 2
Appendix B - Four-Factor Control Cost Analysis
Table 7 - Gas Suspension Absorber (GSA)

Operating Unit: **Line 2**

Emission Unit Number	EU 042		Stack/Vent Number	SV 048 & 049	
Expected Utilization Rate	100%		Temperature	300	Deg F
Expected Annual Hours of Operation	8,376	Hours	Moisture Content	6.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	1,120,210	acfm
Expected Equipment Life	20	yrs	Standardized Flow Rate	778,251	scfm @ 68º F
Pellet Throughput	600	LTon/hr	Dry Std Flow Rate	729,057	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								22,356,887
Purchased Equipment Total (B)	10%	of control device cost (A)						**24,592,575**
Installation - Standard Costs	74%	of purchased equip cost (B)						18,198,506
Installation - Site Specific Costs								61,304,825
Installation Total								18,198,506
Total Direct Capital Cost, DC								42,791,081
Total Indirect Capital Costs, IC	42%	of purchased equip cost (B)						10,328,882
Total Capital Investment (TCI) with Site-specific costs								**113,793,152**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						5,453,619
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						14,611,193
Savings from Shutdown of Existing Emission Controls								(1,307,161)
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**18,757,651**

Emission Control Cost Calculation

			Actual Emissions					
Pollutant	**Max Emis lb/hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc.**	**Conc. Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
Sulfur Dioxide (SO_2):	51.4	215	50.2%	5	ppm	107.2	108	$173,347

Notes & Assumptions

1 Purchased equipment costs from independent review by Zachry Engineering scaled for inflation using the Chemical Engineering Plant Cost Index

2 Capital equipment cost includes the items listed below, which are calculated using EPA cost control manual guidance.

3 GSA/SDA designed for 5 ppm exit SO2 concentration

4 6/18/2012 email from Candice Maxwell, Cleveland Cliffs in response to EPA Region 5 CAA Section 114 information request for scrubber operating costs. Email reported total annual operating costs for both Scrubbers. Listed value excludes capital recover costs and is pro-rated by scrubber exhaust flow rate. Value includes continuing operations cost, per a 9/26/12 e-mail from Jen Krause, Cleveland Cliffs.

5 Retrofit factors are not included because the costs are based on a site-specific estimate

6 Site specific installation costs from independent review by Zachry Engineering.

7 Labor required for handling of lime shipments entering and exiting the facility. Includes spill prevention/cleanup and truck cleaning.

8 Determined from Table 3.21 of Chapter 3 of EPA's September 1999 Particulate Matter control design guidelines (for ESPs)

9 Labor and maintenance materials are 5% of capital costs per CueCost. "Average process with normal operating conditions should have maintenance labor and material costs" of 5 to 9% of fixed capital investment. (page 134, Plant Design and Economics for Chemical Engineers, Max Peters and Klaus Timmerhaus; McGraw-Hill Book Company)

10 Determined from Table 1.11 of Chapter 1 of EPA's December 1998 Particulate Matter control design guidelines (for FFs and baghouses)

11 Contingency and freight are accounted for under Site Specific Installed Equipment Costs.

Cleveland Cliffs: United Taconite Line 2
Appendix B - Four-Factor Control Cost Analysis
Table 7 - Gas Suspension Absorber (GSA)

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A)			
Purchased Equipment Costs (A)			**22,356,887**
Instrumentation	10%	of control device cost (A)	2,235,689
MN Sales Taxes	0%	of control device cost (A)	0
Freight	0%	of control device cost (A)	0
Purchased Equipment Total (B)	10%		**24,592,575**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	983,703
Handling & erection	50%	of purchased equip cost (B)	12,296,288
Electrical	8%	of purchased equip cost (B)	1,967,406
Piping	1%	of purchased equip cost (B)	245,926
Insulation	7%	of purchased equip cost (B)	1,721,480
Painting	4%	of purchased equip cost (B)	983,703
Installation Subtotal Standard Expenses	74%		**18,198,506**
Total Direct Capital Cost, DC			**42,791,081**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	2,459,258
Construction & field expenses	20%	of purchased equip cost (B)	4,918,515
Contractor fees	10%	of purchased equip cost (B)	2,459,258
Start-up	1%	of purchased equip cost (B)	245,926
Performance test	1%	of purchased equip cost (B)	245,926
Model Studies	NA	of purchased equip cost (B)	NA
Contingencies	0%	of purchased equip cost (B)	0
Total Indirect Capital Costs, IC	42%	of purchased equip cost (B)	**10,328,882**
Total Capital Investment (TCI) = DC + IC			**53,119,963**
TCI Adj for Baghouse Filter Replacement			**52,488,326**
Retrofit multiplier	0%	of TCI	**0**
Site Specific Installed Equipment Costs			
Civil/Structural			1,664,454
Mechanical Equipment			38,450,302
Electrical and Control			4,839,425
Freight			1,404,916
Total Indirect Costs + Contingencies			9,079,168
Lost Production for Tie-In	N/A	Site Specific	5,866,560
Total Site Specific Costs			**61,304,825**
Total Capital Investment (TCI) Retrofit Installed			**113,793,152**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	72.12	$/Hr, 5.0 hr/8 hr shift, Annual Operating Hours	427,551
Supervisor	15%	15% of Operator Costs	64,133
Maintenance			
Maintenance Labor	72.12	$/hr, Maint Labor Use Rate+ESP Maint Labor Use Rate	75,510
Maintenance Materials	100%	of maintenance labor costs + 1% ESP purchase cost	328,360
Utilities, Supplies, Replacements & Waste Management			
Compressed Air	$ 0.48	$/kscf	539,357
Electricity	0.07	$/kwh, 6,435 kW-hr, annual operating hours, 100% utilization	3,688,680
Filter Bag Replacement			234,119
Solid Waste Disposal	44.35	$/ton, 136 lb/hr, annual operating hours, 100% utilization	25,228
Lime	183.68	$/ton, 92 lb/hr, annual operating hours, 100% utilization	70,682
Total Annual Direct Operating Costs			**5,453,619**
Savings from Shutdown of Existing Emission Controls			**(1,307,161)**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	537,332
Administration (2% total capital costs)	2%	of total capital costs (TCI)	2,275,863
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	1,137,932
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	1,137,932
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	9,522,135
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**14,611,193**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**18,757,651**

See Summary page for notes and assumptions

Cleveland Cliffs: United Taconite Line 2
Appendix B - Four-Factor Control Cost Analysis
Table 7 - Gas Suspension Absorber (GSA)

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Catalyst:		
Equipment Life	20	years
CRF	0.0000	
Rep part cost per unit	0	$\$/ft^3$
Amount Required	0	ft^3
Packing Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment: Filter Bags and Cages			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	116.70	$ each	Price of 1 bag plus 1/2 price of 1 cage, from Zachry.
Amount Required	4488	Number	Number of bags, from Ducon proposal.
Total Rep Parts Cost	523,745	Cost adjusted for freight & sales tax	
Installation Labor	107,892		OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost	**631,637**	**Zero out if no replacement parts needed**	
Annualized Cost	**234,119**		

Electrical Use							
	Flow acfm		Δ P in H2O	**Efficiency**	**Hp**	**kW**	
Process ID Fan	-		-	-	1,500.0	1,125.0	Fan size from Zachry cost estimates.
Process ID Fan	-		-	-	1,500.0	1,125.0	Fan size from Zachry cost estimates.
Process Booster Fan	-		-	-	2,500.0	1,875.0	Fan size from Zachry cost estimates.
Process Booster Fan	-		-	-	2,500.0	1,875.0	Fan size from Zachry cost estimates.
	Flow	**Liquid SPGR**	**Δ P ft H2O**	**Efficiency**	**Hp**	**kW**	
Circ Pump	000 gpm	1	60	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
H2O WW Disch	0 gpm	1	60	0.7	-	0.0	EPA Cost Cont Manual 6th ed Section 5.2 Chapter 1 Eq 1.49
		SCA[1] **ft^2/kacfm**	**Plate Area** **ft^2**	**kW/ft^2**			
ESP Power		200	224,042	1.94E-03		434.6	EPA Cont Cost Manual 6th ed - Sec 6 Ch 3 Eq 3.48
Other							
Total						6434.6	

Reagent Use & Other Operating Costs				
Hydrated Lime Use	51.43	lb/hr SO2 no scrubber	91.88	lb/hr lime, lime addition
NSR	1.30		114.63	lb CaSO3/hr
Waste Lime			21.20	lb/hr waste lime
Total Waste			135.84	lb/hr waste

An NSR of 1.3 means that 30% more lime is injected than is needed to capture SO2.

Operating Cost Calculations

Annual hours of operation: **8,376**
Utilization Rate: **100%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor BH + ESP	72.12	$/Hr	5.0	hr/8 hr shift	5,235	377,548	$/Hr, 5.0 hr/8 hr shift, Annual Operating Hours
Lime Handling Labor	72.12	$/Hr	13.3	hr/week	693.3	50,003	$/Hr, 13.3 hr/week, Annual Operating Hours
Supervisor	15%	of Op.			NA	64,133	15% of Operator Costs
Maintenance							
Maint Labor Baghouse	72.12	$/Hr	1.0	hr/8 hr shift	1,047	75,510	$/Hr, 1.0 hr/8 hr shift, Annual Operating Hours
Maint Mtls Baghouse	100	% of Maintenance Labor			NA	75,510	100% of Maintenance Labor
ESP Maint Mtls and Lbr	5	% of ESP purchase cost				252,850	5% of ESP Purchase Cost
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.068	$/kwh	6434.6	kW-hr	53,896,557	3,688,680	$/kwh, 6,435 kW-hr, annual operating hours, 100% utilization
Water	0.01	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, annual operating hours, 100% utilization
Solid Waste Disposal	44.35	$/ton	135.8	lb/hr	569	25,228	$/ton, 136 lb/hr, annual operating hours, 100% utilization
Lime	183.7	$/ton	91.9	lb/hr	385	70,682	$/ton, 92 lb/hr, annual operating hours, 100% utilization
Filter Bag Replacement						234,119	2012 Dry FGD Study - Opinion of Probable Cost O&M Costs
Compressed Air	$ 0.48	$/kscf	2	scfm/kacfm	1,125,945	539,357	$/yr

*annual use rate is in same units of measurement as the unit cost factor

See Summary page for notes and assumptions

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January 29, 2020

Chrissy Bartovich, Environmental Health and Safety Administrator
U.S. Steel Corporation - Keetac
1 Mine Road
Keewatin, MN 55753

RE: Request for Information - Regional Haze Rule, Reasonable Progress, Four Factor Analysis

Dear Ms. Bartovich:

The Minnesota Pollution Control Agency (MPCA) is currently preparing information for the second planning period (Round 2) comprehensive update to Minnesota's Regional Haze State Implementation Plan (SIP) as required by the Regional Haze Rule (40 CFR § 51.308). States are responsible for developing a Regional Haze SIP that addresses regional haze in each Class I area located within the state and in each Class I area located outside the state which may be affected by emissions from sources within the state. The Regional Haze SIP is required to identify existing facilities that cause or contribute to visibility impairment; analyze, identify, and apply federally-enforceable control strategies for those sources; and periodically demonstrate reasonable progress toward reaching visibility goals. States are also responsible for periodic comprehensive updates to their Regional Haze SIP that address these same topics. Minnesota's Round 2 Regional Haze SIP must be submitted to the U.S. Environmental Protection Agency (U.S. EPA) by July 31, 2021.

Minnesota has two Class I areas within its borders, the Boundary Waters Canoe Area Wilderness (BWCA) and Voyageurs National Park (Voyageurs). Other nearby Class I areas include Isle Royale National Park in Michigan. Therefore, Minnesota must prepare a Regional Haze SIP that identifies sources that cause or contribute to visibility impairment in these areas. To meet the core requirements for regional haze for these areas, Minnesota must submit a SIP that contains the plan elements and supporting documentation for all required analyses identified in 40 CFR § 51.308(f).

In the first planning period (Round 1), the focus of the Regional Haze Rule was on establishing Best Available Retrofit Technology (BART) for certain older sources and reasonable progress towards national visibility goals. In Round 2, there are no BART requirements; therefore, the focus is on making reasonable progress. The U.S. Environmental Protection agency has defined the methodology that states must use to determine what measures are necessary to make reasonable progress in 40 CFR § 51.308(f)(2). At minimum, the reasonable progress analysis must use the four factors identified in 40 CFR § 51.308(f)(2)(i) to evaluate and determine the emission reduction measures necessary to make reasonable progress. The four factors are:

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

Data from the IMPROVE monitoring sites at BWCA and Voyageurs indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X).

You are receiving this letter because your facility was identified as a significant source of NO_X and SO_2 and is located close enough to the BWCA or Voyageurs to potentially cause or contribute to visibility impairment in these Class I areas. Therefore, the MPCA requests that you prepare a "Four Factor Analysis" for the following emission units:

1. Grate Kiln - Indurator Waste Gas, Phase II (EQUI 97 / EU 030) that addresses emissions of NO_X and SO_2

The analysis should be prepared using the U.S. Environmental Protection Agency guidance[1] that provides recommendations for how each of the factors should be determined.

Preparation of the comprehensive update to Minnesota's Regional Haze SIP will require extensive planning and review of sources in Minnesota. The MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to prepare the Regional Haze SIP. The MPCA expects air quality modeling of potential regional emissions reductions will be conducted beginning in spring 2020. I appreciate your attention to this matter and request that you **submit the Four Factor Analysis by July 31, 2020**.

If you have any questions regarding this matter, or would like to request a meeting to further discuss the contents of this letter, please contact me by phone at 651-757-2653 or by email at Hassan.Bouchareb@state.mn.us.

Sincerely,

Hassan Bouchareb

This document has been electronically signed.

Hassan M. Bouchareb
Engineer
Environmental Analysis and Outcomes Division

Cc: Deepa de Alwis, MPCA
Cory Boeck, MPCA
Frank Kohlasch, MPCA
Agency Interest ID 142828

Address questions and submittals requested above to:

Hassan M. Bouchareb
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155-4194
(651) 757-2653
Hassan.Bouchareb@state.mn.us

---

[1] **U.S. Environmental Protection Agency.** *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 20, 2019, https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

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January 29, 2020

Chrissy Bartovich, Environmental Health and Safety Administrator
U.S. Steel Corporation - Minntac
8771 Park Ridge Drive
Mountain Iron, MN 55768

RE: Request for Information - Regional Haze Rule, Reasonable Progress, Four Factor Analysis

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

Data from the IMPROVE monitoring sites at BWCA and Voyageurs indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X).

You are receiving this letter because your facility was identified as a significant source of NO_X and SO_2 and is located close enough to the BWCA or Voyageurs to potentially cause or contribute to visibility impairment in these Class I areas. Therefore, the MPCA requests that you prepare a "Four Factor Analysis" for the following emission units:

1. Line 3 Rotary Kiln (EQUI 146 / EU 225) that addresses emissions of NO_X and SO_2
2. Line 4 Rotary Kiln (EQUI 279 / EU 261) that addresses emissions of NO_X and SO_2
3. Line 5 Rotary Kiln (EQUI 280 / EU 282) that addresses emissions of NO_X and SO_2
4. Line 6 Rotary Kiln (EQUI 3 / EU 315) that addresses emissions of NO_X and SO_2
5. Line 7 Rotary Kiln (EQUI 179 / EU 334) that addresses emissions of NO_X and SO_2

The analysis should be prepared using the U.S. Environmental Protection Agency guidance[1] that provides recommendations for how each of the factors should be determined.

Preparation of the comprehensive update to Minnesota's Regional Haze SIP will require extensive planning and review of sources in Minnesota. The MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to prepare the Regional Haze SIP. The MPCA expects air quality modeling of potential regional emissions reductions will be conducted beginning in spring 2020. I appreciate your attention to this matter and request that you **submit the Four Factor Analysis by July 31, 2020**.

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Sincerely,

Hassan Bouchareb

This document has been electronically signed.

Hassan M. Bouchareb
Engineer
Environmental Analysis and Outcomes Division

Cc: Deepa de Alwis, MPCA
Cory Boeck, MPCA
Frank Kohlasch, MPCA
Agency Interest ID 2476

---

[1] **U.S. Environmental Protection Agency.** *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 20, 2019, https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

Address questions and submittals requested above to:

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Regional Haze Four-Factor Analysis Applicability Evaluation

Grate Kiln – Indurator Waste Gas, Phase II (EQUI 97/EU 030)

Prepared for
United States Steel Corporation, Minnesota Ore Operations - Keetac

May 29, 2020

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Regional Haze Four-Factor Analysis Applicability Evaluation

May 29, 2020

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Appendix A	Visibility Impacts

1 Executive Summary

On January 29, 2020 the Minnesota Pollution Control Agency (MPCA) submitted a Request for Information (RFI) Letter[1] to United States Steel Corporation, Minnesota Ore Operations – Keetac (Keetac) to consider potential emissions reduction measures of nitrogen oxides (NO_X) and sulfur dioxide (SO_2) from the facility's Grate Kiln – Indurator Waste Gas, Phase II (EQUI 97/EU 030) (grate-kiln) by addressing the four statutory factors laid out in 40 CFR 51.308(f)(2)(i), as explained in the August 2019 U.S. EPA Guidance (2019 Guidance)[2]:

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

Emission reduction evaluations addressing these factors are commonly referred to as "four-factor analyses." MPCA set a July 31, 2020 deadline for Keetac to submit a four-factor analysis. The MPCA intends to use the four-factor analyses to evaluate additional control measures as part of the development of the State Implementation Plan (SIP), which must be submitted to United States Environmental Protection Agency (USEPA) by July 31, 2021. The SIP will be prepared to address the second regional haze implementation period, which ends in 2028.

This report considers whether a four-factor analysis is warranted for Keetac because the grate-kiln can be classified as an "effectively controlled" source for NO_x and SO_2. The MPCA can exclude such sources for evaluation per the regulatory requirements of the Regional Haze Rule[3] (RHR) and the 2019 Guidance.

This report provides evidence that it would be reasonable for MPCA to exclude Keetac from the group of sources analyzed for control measures for the second implementation period and to withdraw its request for a four-factor analysis for the grate-kiln based on the following points (with additional details provided in cited report sections):

- The grate-kiln meets the BART-required control equipment installation scenario and is an "effectively controlled" source for NO_x and SO_2. Keetac has BART emission controls and emission limits for NO_X and SO_2 in accordance with 40 CFR 52.1235(b)(1) and 52.1235(b)(2), respectively.

---

[1] January 29, 2020 letter from Hassan Bouchareb of MPCA to United States Steel Corporation, Minnesota Ore Operations – Keetac.

[2] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[3] USEPA, Regional Haze Rule Requirements – Long Term Strategy for Regional Haze, 40 CFR 52.308(f)(2)

The associated BART analyses are provided in the August 2012[4] and October 2015[5] USEPA Federal Implementation Plan (FIP) rulemaking. (see Section 5)

- The RHR and the 2019 Guidance both give states the ability to focus their analyses in one implementation period on a set of sources that differ from those analyzed in another implementation period. (see Section 2.1.3.2)
- There has been significant progress on visibility improvement in the nearby Class I areas and MPCA's reasonable progress goals should be commensurate with this progress. (see Section 3.1)
- The grate-kiln does not materially impact visibility from a theoretical (modeling) and empirical (actual visibility data) basis and should not be required to assess additional emission control measures. (see Section 4)

Additional emission reductions from the grate-kiln at Keetac will not contribute meaningfully to further reasonable progress. Therefore Keetac requests MPCA withdraw its request for a four-factor analysis for the grate-kiln.

---

[4] USEPA, Federal Register, 08/15/2012, Page 49308.

[5] USEPA, Federal Register, 10/22/2015, Page 64160.

2 Introduction

Section 2.1 discusses the RFI provided to Keetac by MPCA, pertinent regulatory background for regional haze State Implementation Plans (SIP) development and relevant guidance issued by USEPA to assist States in preparing their SIPs, specifically regarding the selection of sources that must conduct an emissions control evaluation. Section 2.2 provides a description of Keetac's indurating furnace.

2.1 Regulatory Background

2.1.1 Minnesota's Request for Information (RFI)

"Regional haze" is defined at 40 CFR 51.301 as "visibility impairment that is caused by the emission of air pollutants from numerous anthropogenic sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources." The RHR requires state regulatory agencies to submit a series of SIPs in ten-year increments to protect visibility in certain national parks and wilderness areas, known as mandatory Federal Class I areas. The original State SIPs were due on December 17, 2007 and included milestones for establishing reasonable progress towards the visibility improvement goals, with the ultimate goal to achieve natural background visibility by 2064. The initial SIP was informed by best available retrofit technology (BART) analyses that were completed on all BART-subject sources. The second RHR implementation period ends in 2028 and requires development and submittal of a comprehensive SIP update by July 31, 2021.

As part of the second RHR implementation period SIP development, the MPCA sent an RFI to Keetac on January 29, 2020. The RFI stated that data from the IMPROVE (Interagency Monitoring of Protected Visual Environments) monitoring sites at Boundary Waters Canoe Area (BWCA) and Voyageurs National Park (Voyageurs) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of SO_2 and NO_X that react with available ammonia. In addition, emissions from sources in Minnesota could potentially impact Class I areas in nearby states, namely Isle Royale National Park (Isle Royale) in Michigan.[6] As part of the planning process for the SIP development, MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to evaluate regional emission reductions.

The RFI also stated that Keetac was identified as a significant source of NO_X and SO_2 and is located close enough to the BWCA and Voyageurs to potentially cause or contribute to visibility impairment. Therefore, the MPCA requested that Keetac submit a "four-factors analysis" (herein termed as a "four-factor analysis") evaluating potential emissions control measures, pursuant to 40 CFR 51.308(f)(2)(i)[7], by July 31, 2020 for the emission units identified in Table 2-1.

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[6] Although Michigan is responsible for evaluating haze in Isle Royale, it must consult with surrounding states, including Minnesota, on potential cross-state haze pollution impacts.

[7] The four statutory factors are 1) cost of compliance, 2) time necessary for compliance, 3) energy and non-air quality environmental impacts of compliance, and 4) remaining useful life of the source.

Table 2-1 Identified Emission Units

Unit	Unit ID	Applicable Pollutants
Grate Kiln – Indurator Waste Gas, Phase II	(EQUI 97/EU 030)	NO_X, SO_2

The RFI to Keetac specified that the "analysis should be prepared using the U.S. Environmental Protection Agency guidance" referring to USEPA guidance as issued on August 20, 2019[8].

2.1.2 SIP Revision Requirements

The regulatory requirements for comprehensive revisions to the SIP are provided in 40 CFR 51.308(f). The next revision must be submitted to USEPA by July 31, 2021 and must include a commitment to submit periodic reports describing progress towards the reasonable progress goals as detailed in 40 CFR 51.308(g). The SIP "must address regional haze in each mandatory Class I Federal area located within the State and in each mandatory Class I Federal area located outside the State that may be affected by emissions from within the State."

Each SIP revision is required to address several elements, including "calculations of baseline, current, and natural visibility conditions; progress to date; and the uniform rate of progress."[9] The baseline conditions are based on monitoring data from 2000 to 2004 while the target conditions for natural visibility are determined using USEPA guidance. The State will then determine the uniform rate of progress (URP) which compares "the baseline visibility condition for the most impaired days to the natural visibility condition for the most impaired days and determine the uniform rate of visibility improvement (measured in deciviews of improvement per year) that would need to be maintained during each implementation period in order to attain natural visibility conditions by the end of 2064."[10]

The SIP revision must also include the "Long-term strategy for regional haze."[11] The strategy "must include the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress" towards the natural visibility goal. There are several criteria that must be considered when developing the strategy, including an evaluation of emission controls (the four-factor analysis) at selected facilities to determine emission reductions necessary to make reasonable progress. The SIP must consider other factors in developing its long-term strategy, including: emission reductions due to other air pollution control programs[12], emission unit retirement and replacement

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[8] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[9] 40 CFR 51.308(f)(1)

[10] 40 CFR 51.308(f)(1)(vi)(A)

[11] 40 CFR 51.308(f)(2)

[12] 51.308(f)(2)(iv)(A)

schedules[13], and the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions during the implementation period[14].

In addition, the SIP must include "reasonable progress goals" that reflect the visibility conditions that are anticipated to be achieved by the end of the implementation period through the implementation of the long term strategy and other requirements of the Clean Air Act (CAA)[15]. The reasonable progress goal is not enforceable but will be considered by USEPA in evaluating the adequacy of the SIP[16].

2.1.3 USEPA Guidance for SIP Development

On August 20, 2019, the USEPA issued "*Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*"[17] USEPA's primary goal in issuing the 2019 Guidance was to help states develop "approvable" SIPs. EPA also stated that the document supports key principles in SIP development, such as "leveraging emission reductions achieved through CAA and other programs that further improve visibility in protected areas."[18]

The 2019 Guidance says SIPs must be "consistent with applicable requirements of the CAA and EPA regulations, and are the product of reasoned decision-making"[19] but also emphasizes States' discretion and flexibility in the development of their SIPs. For instance, the 2019 Guidance states, "A key flexibility of the regional haze program is that a state is *not* required to evaluate all sources of emissions in each implementation period. Instead, a state may reasonably select a set of sources for an analysis of control measures."[20] The 2019 Guidance notes this flexibility to not consider every emission source stems directly from CAA § 169A(b)(2) and 40 CFR § 51.308(f)(2)(i), the section of the RHR the MPCA cites in its letter.[21]

The 2019 Guidance lists eight key process steps that USEPA anticipates States will follow when developing their SIPs. This report focuses on the selection of sources which must conduct a four-factor analysis and references the following guidance elements which impact the selection:

- Ambient data analysis (Step 1), including the progress, degradation and URP glidepath checks (Step 7)
- Selection of sources for analysis (Step 3), with a focus on:
    - Estimating baseline visibility impacts for source selection (Step 3b)

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[13] 51.308(f)(2)(iv)(C)

[14] 51.308(f)(2)(iv)(E)

[15] 40 CFR 51.308(f)(3)

[16] 40 CFR 51.308(f)(3)(iii)

[17] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[18] Ibid, page 1.

[19] Ibid.

[20] Ibid, page 9 (emphasis added).

[21] Ibid.

- Sources that already have effective emission control technology in place (Step 3f)

2.1.3.1 Ambient Data Analysis

As stated in Section 2.1.2, the RHR requires each state with a Class I area to calculate the baseline, current, and natural visibility conditions as well as to determine the visibility progress to date and the URP. The visibility metric is based on the 20% most anthropogenically impaired days and the 20% clearest days, with visibility being measured in deciviews (dv). The guidance provides the following equation for calculating the Uniform Rate of Progress (URP):[22]

$$\text{URP} = [(\text{2000-2004 visibility})_{\text{20\% most impaired}} - (\text{natural visibility})_{\text{20\% most impaired}}]/60$$

The visibility from 2000-2004 represents the baseline period, and the natural visibility goal is in 2064, which is why the URP is calculated over a 60-year period.

At the end of the SIP development process a State must estimate the visibility conditions for the end of the implementation period and then must complete a comparison of the reasonable progress goals to the baseline visibility conditions and the URP glidepath. The guidance explains that the RHR does not define the URP as the target for "reasonable progress" and further states that if the 2028 estimate is below the URP glidepath, that does not exempt the State from considering the four-factor analysis for select sources.[23] However, the current visibility conditions compared to the URP glidepath will be a factor when determining the reasonable progress goal.

In Section 3, Barr evaluates the visibility improvement progress to date at BWCA, Voyageurs and Isle Royale using the IMPROVE network visibility data from MPCA's website. This analysis was conducted to document the current visibility conditions compared to the URP, which can provide insight into the amount of emission reductions necessary to have the 2028 visibility conditions below the URP.

2.1.3.2 Selection of sources for analysis

The 2019 Guidance emphasizes that the RHR provides flexibility in selecting sources that must conduct an emission control measures analysis:

> "…a state is not required to evaluate all sources of emissions in each implementation period. Instead, a state may reasonably select a set of sources for an analysis of control measures…."[24]

The 2019 Guidance goes on to justify this approach (emphasis added):

> "Selecting a set of sources for analysis of control measures in each implementation period is also consistent with the Regional Haze Rule, which sets up an iterative planning process and anticipates that a state may not need to analyze control measures for all its sources in a given SIP revision. Specifically, section 51.308(f)(2)(i) of the Regional Haze Rule requires a SIP to include a

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[22] Ibid, Page 7.

[23] Ibid, Page 50.

[24] Ibid, Page 9.

> description of the criteria the state has used to determine the sources or groups of sources it evaluated for potential controls. Accordingly, it is reasonable and permissible for a state to distribute its own analytical work, and the compliance expenditures of source owners, over time by addressing some sources in the second implementation period and other sources in later periods. For the sources that are not selected for an analysis of control measures for purposes of the second implementation period, it may be appropriate for a state to consider whether measures for such sources are necessary to make reasonable progress in later implementation periods."[25]

The 2019 Guidance further states that there is not a list of factors that a state must consider when selecting sources to evaluate control measures, but the state must choose factors and apply them in a reasonable way to make progress towards natural visibility. The guidance details several factors that could be considered, including:

- the in-place emission control measures and, by implication, the emission reductions that are possible to achieve at the source through additional measures[26]
- the four statutory factors (to the extent they have been characterized at this point in SIP development)[27]
- potential visibility benefits (also to the extent they have been characterized at this point in SIP development)[28]
- sources already having effective emissions controls in place[29]
- emission reductions at the source due to ongoing air pollution control programs[30]
- in-state emission reductions due to ongoing air pollution control programs that will result in an improvement in visibility[31]

Furthermore, the 2019 Guidance states that "An initial assessment of projected visibility impairment in 2028, considering growth and on-the books controls, can be a useful piece of information for states to consider as they decide how to select sources for control measure evaluation."[32]

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[25] Ibid, Page 9.

[26] Ibid, Page 10.

[27] Ibid.

[28] Ibid.

[29] Ibid, Page 21.

[30] Ibid, Page 22.

[31] Ibid.

[32] Ibid, Page 10.

2.1.3.2.1 Estimating Baseline Visibility Impacts for Source Selection

When selecting sources to conduct an emission control evaluation, the 2019 Guidance says that the state may use a "reasonable surrogate metrics of visibility impacts." The guidance provides the following techniques to consider and says that "other reasonable techniques" may also be considered[33]:

- Emissions divided by distance (Q/d)
- Trajectory analyses
- Residence time analyses
- Photochemical modeling

In regards to documenting the source selection process, the 2019 Guidance states:[34]

> "EPA recommends that this documentation and description provide both a summary of the state's source selection approach and a detailed description of how the state used technical information to select a reasonable set of sources for an analysis of control measures for the second implementation period. The state could include qualitative and quantitative information such as: the basis for the visibility impact thresholds the state used (if applicable), additional factors the state considered during its selection process, and any other relevant information."

In Section 4, Barr presents a trajectory analysis using data from the IMPROVE monitoring network as presented on MPCA's website and photochemical modeling results to demonstrate that it is not appropriate to select the taconite indurating furnaces as sources subject to the emissions control measures analysis because reducing the emissions will not have a large impact on visibility. Section 4 also presents information from the IMPROVE monitoring system which demonstrates that there was not a noticeable improvement in visibility in 2009 when the taconite plants experienced a production curtailment due to a recession which indicates that the reduction of pollutants from taconite facilities will not result in a discernable visibility improvement in the Class 1 areas.

2.1.3.3 Sources that Already have Effective Emission Control Technology in Place

The 2019 Guidance identified eight example scenarios and described the associated rationale for when sources should be considered "effectively controlled" and that states can exclude similar sources from needing to complete a "four-factor analysis."[35] One of the "effectively controlled" scenarios is for "BART-eligible units that installed and began operating controls to meet BART emission limits for the first implementation period."[36] USEPA caveats this scenario by clarifying that "states may not categorically exclude all BART-eligible sources, or all sources that installed BART control, as candidates for selection for

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[33] Ibid, Page 12.

[34] Ibid, Page 27.

[35] Ibid, Page 22.

[36] Ibid, Page 25.

analysis of control measures."[37] USEPA further notes that "a state might, however, have a different, reasonable basis for not selecting such sources [BART-eligible and non-BART eligible units that implement BART controls] for control measure analysis."[38]

In Section 5, Barr presents an evaluation of the BART-eligible units scenario and demonstrates that the grate-kiln is an "effectively controlled" source for both NO_X and SO_2. Thus, a four-factor analysis is not warranted for this source because, as USEPA notes, "it may be unlikely that there will be further available reasonable controls for such sources."[39]

2.2 Facility Description

Keetac mines iron ore (magnetite) and produces taconite pellets that are shipped to steel producers for processing in blast furnaces. The iron ore is crushed and routed through several concentration stages including grinding, magnetic separation, and thickening.

A concentrated iron ore slurry is dewatered by vacuum disc filters, mixed with bentonite, and conveyed to balling drums. Greenballs produced in the balling drums are fed to the traveling grate prior to entering the kiln. The traveling grate consists of drying and preheat zones. After greenballs pass through the traveling grate, they enter the kiln where pellets are heated to approximately 2,400 degrees Fahrenheit to facilitate the conversion of magnetite to hematite. After the kiln, the fired pellets are sent to an annular cooler where ambient air is blown through the pellets, which allows them to be safely discharged onto rubber belting. The heated waste gas from the kiln and annular cooler are used for the drying and heating zones on the traveling grate.

Keetac operates a single preheat grate/induration kiln (grate-kiln) furnace. Waste gas from the furnace is controlled by dual venturi wet scrubbers and is vented through a single stack. Figure 2-1 includes a sketch of Keetac's grate-kiln furnace design.

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[37] Ibid.

[38] Ibid.

[39] Ibid.

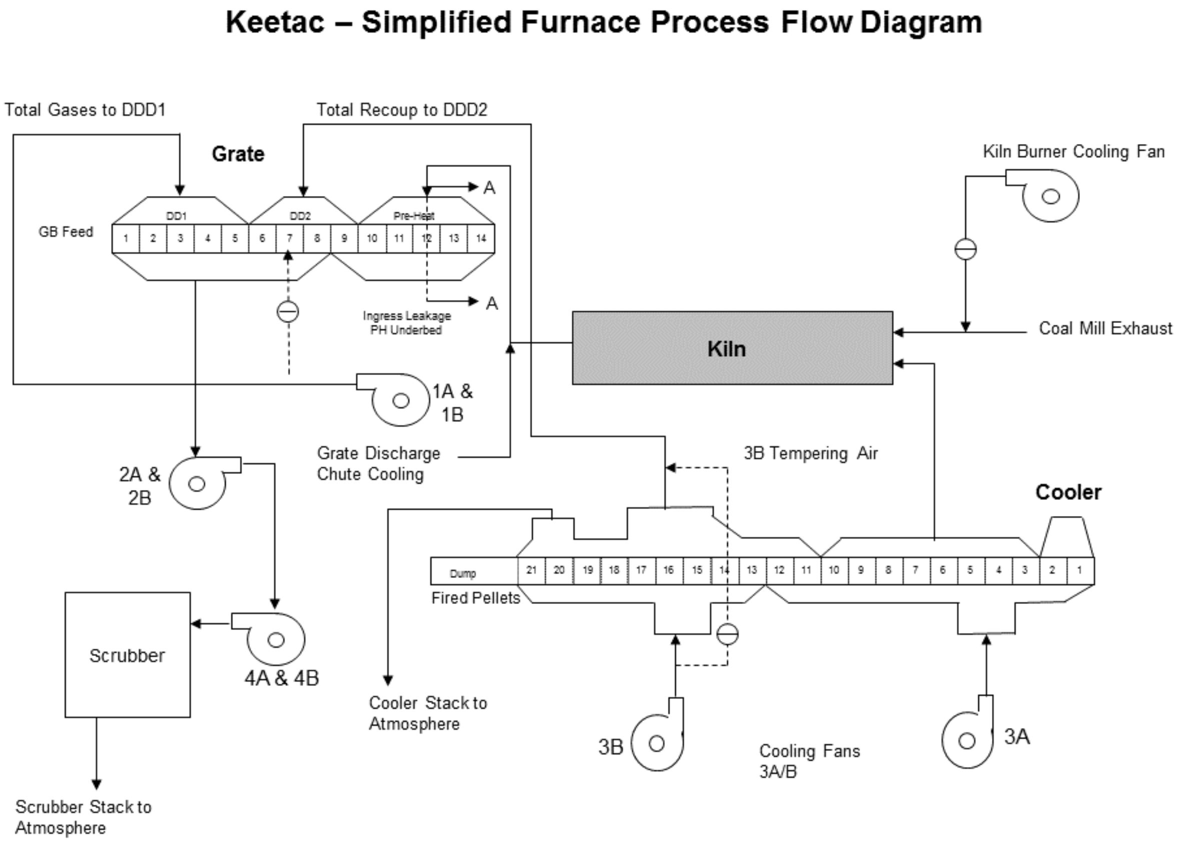
Keetac – Simplified Furnace Process Flow Diagram

Figure 2-1 Grate Kiln – Indurator Waste Gas, Phase II (EQUI 97/EU 030) Diagram

3 Analysis of Ambient Data

As described in Section 2.1.2, the SIP must consider visibility conditions (baseline, current, and natural visibility), progress to date, and the URP. This requirement is referred to as Step 1 on the 2019 Guidance (see Section 2.1.3.1). This information informs the State's long term strategy for regional haze, as required by 51.308(f)(2), and the reasonable progress goals, as required by 51.308(3).

Section 3.1 provides analysis of visibility conditions based on data from the IMPROVE monitoring network at BWCA (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1) and Section 3.2 addresses regional emission reductions. Consistent with 51.308(f)(2)(iv), the regional emission reductions summary considers emission reductions that have occurred but are not yet reflected in the available 5-year average monitoring data set and future emission reductions that will occur prior 2028, which is the end of the second SIP implementation period.

3.1 Visibility Conditions

As summarized in Section 2.1.2, the RHR requires that the SIP include an analysis "of baseline, current, and natural visibility conditions; progress to date; and the uniform rate of progress."[40] This data will be used in the SIP to establish reasonable progress goals (expressed in deciviews) that reflect the visibility conditions that are projected to be achieved by the end of the implementation period (2028) as a result of the implementation of the SIP and the implementation of other regulatory requirements.[41] The reasonable progress goal is determined by comparing the baseline visibility conditions to natural visibility conditions and determining the uniform rate of visibility improvement needed to attain natural visibility conditions by 2064. The SIP "must consider the uniform rate of improvement in visibility and the emission-reduction measures needed to achieve it for the period covered by the implementation plan."[42]

MPCA tracks progress towards the natural visibility conditions using data from the IMPROVE visibility monitors at BWCA (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1).[43] The available regional haze monitoring data was compared to the uniform rate of progress and to the possible reasonable progress goals for the SIP for the implementation period, which ends in 2028. As described in Section 2.1.3.1, the visibility metric is based on the 20% most anthropogenically impaired days and the 20% clearest days, with visibility being measured in deciviews (dv). USEPA issued guidance for tracking visibility progress, including the methods for selecting the "most impaired days," on December 20, 2018.[44] Originally, the RHR considered the "haziest days" but USEPA recognized that naturally occurring events (e.g., wildfires and dust storms) could be contributing to visibility and that the "visibility improvements resulting from decreases in anthropogenic emissions can be hidden in this uncontrollable natural variability."[45] In

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[40] 40 CFR 51.308(f)(1)

[41] 40 CFR 51.308(f)(3)

[42] 40 CFR 51.308(d)(1)

[43] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

[44] https://www.epa.gov/visibility/technical-guidance-tracking-visibility-progress-second-implementation-period-regional

[45] USEPA, Federal Register, 05/04/2016, Page 26948

addition, the RHR allows a state to account for international emissions "to avoid any perception that a state should be aiming to compensate for impacts from international anthropogenic sources."[46]

Figure 3-1 through Figure 3-3 show the rolling 5-year average of visibility impairment versus the URP glidepath[47] at BWCA (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1). Regional haze impairment has been declining since 2009 for all three Class I areas that are tracked by MPCA. Impacts to the most impaired days at BWCA and Isle Royale fell below the expected 2028 URP goal in 2016 and have continued trending downward since. Voyageurs impaired days fell below the 2028 URP in 2018 and is also on a downward trend.

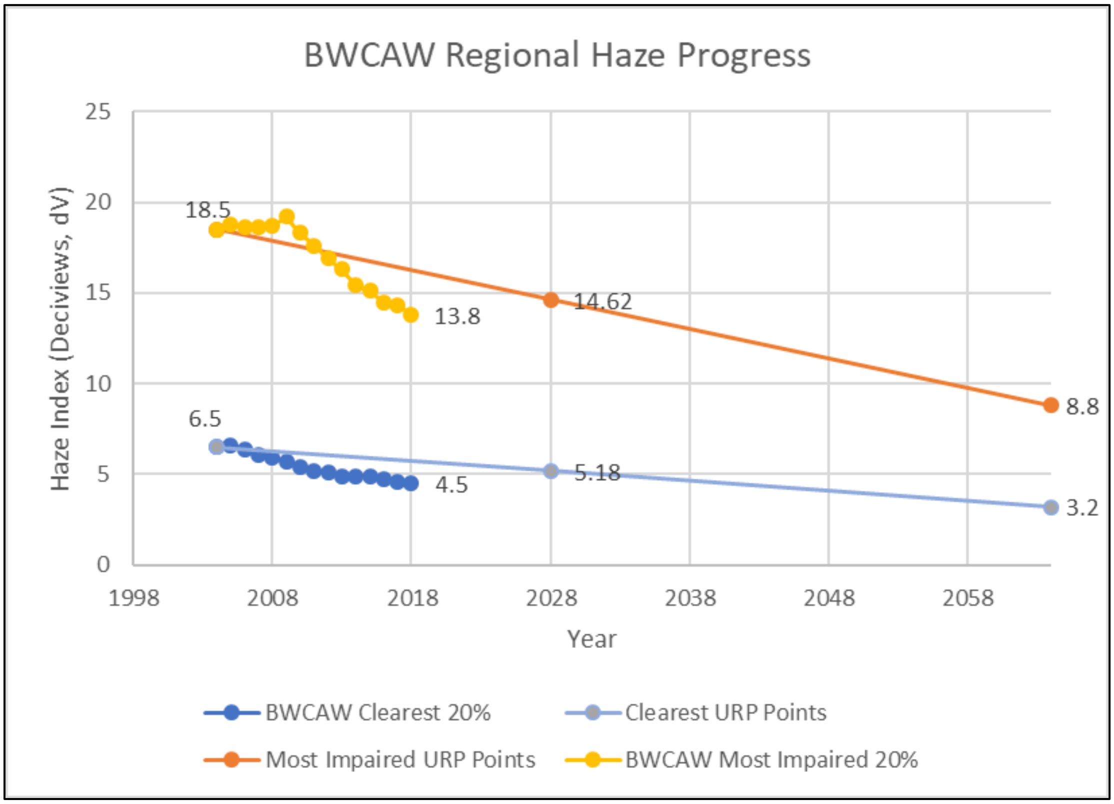

Figure 3-1 Visibility Trend versus URP – Boundary Waters Canoe Area (BOWA1)

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[46] USEPA, Federal Register, 01/10/2017, Page 3104

[47] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

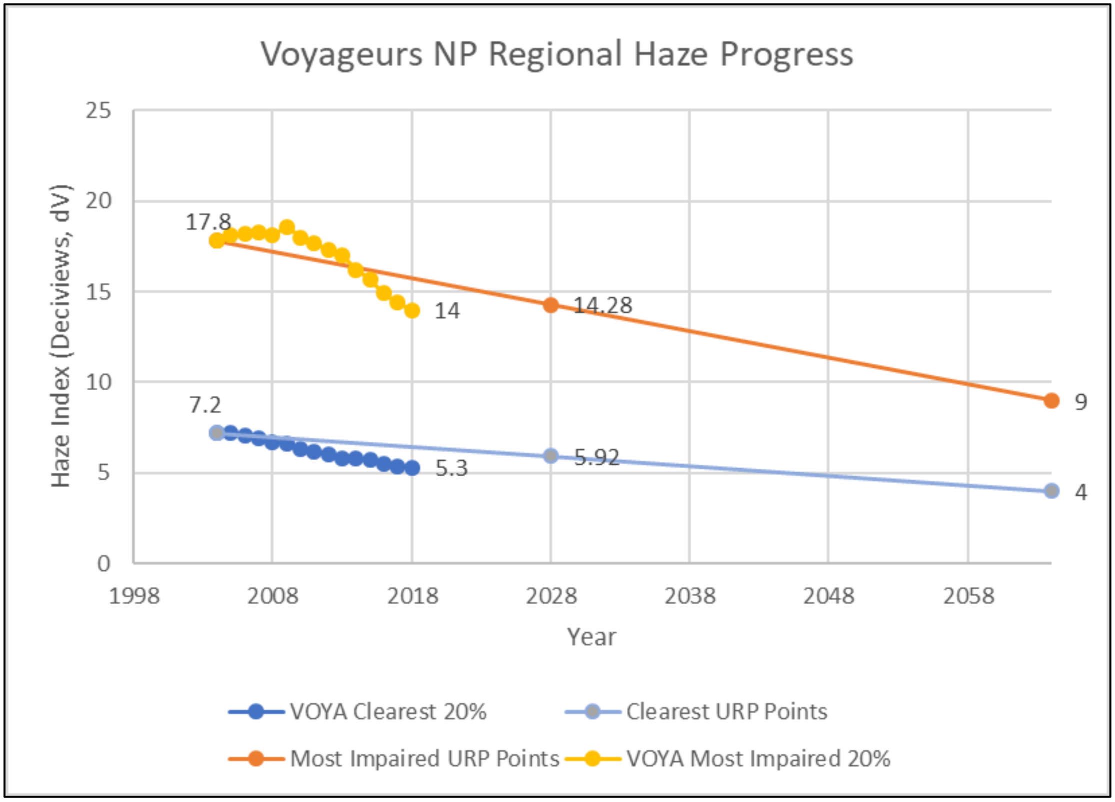

Figure 3-2 Visibility Trend versus URP – Voyageurs National Park (VOYA1)

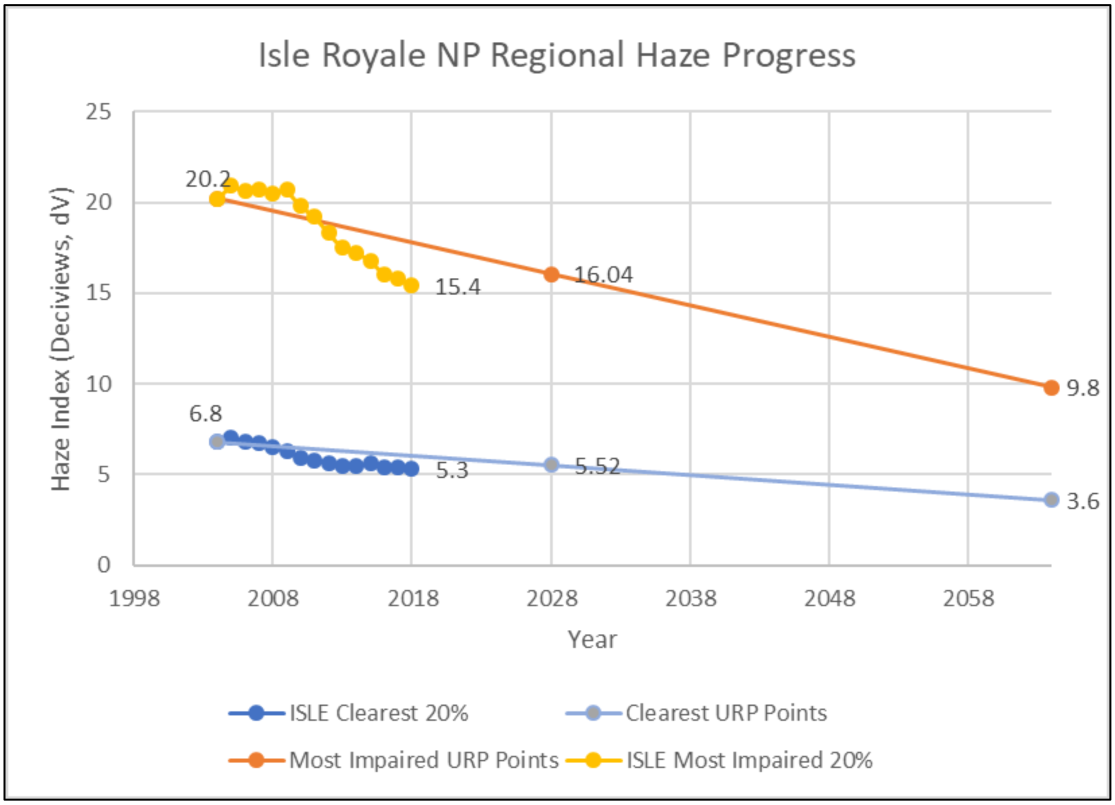

Figure 3-3 Visibility Trend versus URP – Isle Royale National Park (ISLE1)

3.2 Regional emissions reductions

The visibility improvement shown in Figure 3-1 through Figure 3-3 correlates with SO_2 and NO_x emissions decreases from Minnesota's top twenty emission stationary sources, as shown in Figure 3-4[48]. These emission reductions are a result of multiple substantial efforts from the regulated community, including:

- Installation of BART controls during the first implementation period
- Emission reductions at electric utility combustion sources due to new rules and regulations, including:
    - Acid Rain Rules
    - Cross State Air Pollution Rule (CASPR)
    - Mercury and Air Toxics Standards (MATS)
- Electric utility combustion sources undergoing fuel changes (e.g., from coal and to natural gas)
- Increased generation of renewable energy, which decreases reliance on combustion sources

Since many of these emission reduction efforts are due to federal regulations and national trends in electrical generation, similar emission reduction trends are likely occurring in other states.

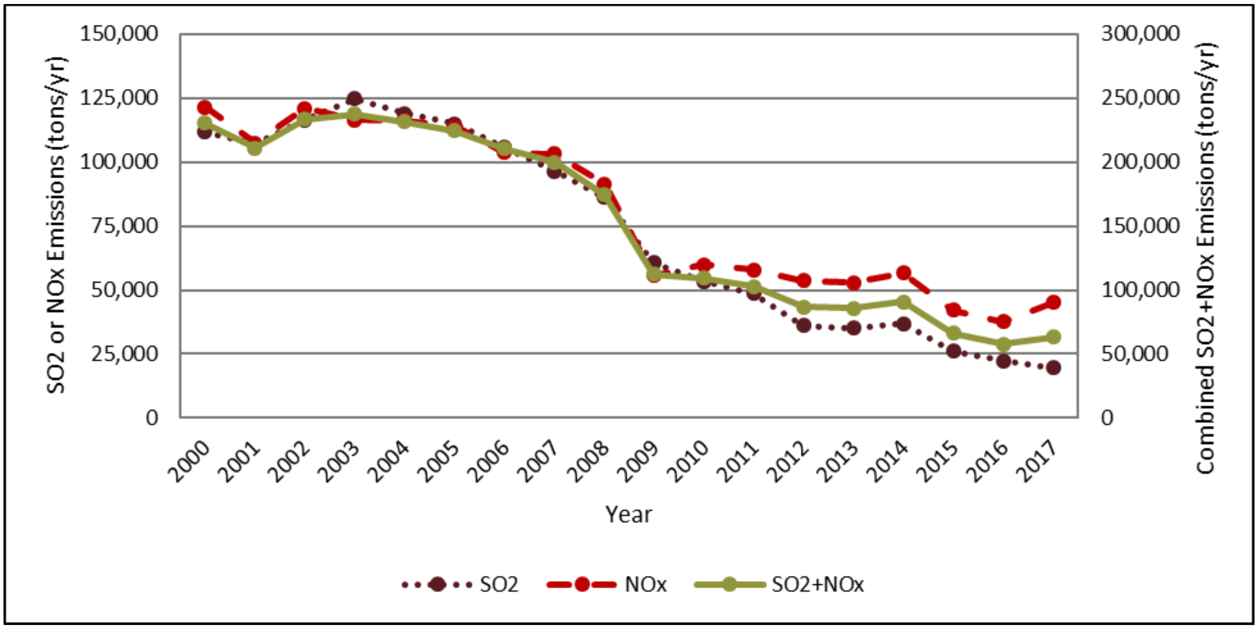

Figure 3-4 Total Emissions of Top-20 Emitters and Taconite Facilities in MN (2000-2017)

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[48] The data for NO_X and SO_2 emissions was downloaded from the MPCA point source emissions inventory (https://www.pca.state.mn.us/air/permitted-facility-air-emissions-data). The permitted facilities that had the 20 highest cumulative emissions from 2000-2017 in MN were chosen for the graphics, along with all six taconite facilities (whether or not they were in the top 20 of the state).

Figure 3-1 through Figure 3-3 show the rolling 5-year average of visibility impairment versus the URP glidepath, so the emissions represented in the most recent data set (2018) is from 2014-2018. However, as shown in Table 3-1, additional emission reductions have occurred since 2014 and are not fully represented in the 5-year visibility data yet. Additionally, several stationary sources have scheduled future emission reductions which will occur prior to 2028. Combined, these current and scheduled emission reductions will further improve visibility in the Class I areas, ensuring the trend stays below the URP. Even without these planned emissions reductions, the 2018 visibility data is already below the 2028 glidepath. As such, MPCA's second SIP implementation period strategy should be commensurate with the region's visibility progress and it would be reasonable for MPCA to not include the taconite indurating furnaces when "reasonably select[ing] a set of sources for an analysis of control measures," and such decision is supported by the 2019 Guidance.

Table 3-1 Notable Minnesota Emission Reductions

Year	Additional Emissions Reductions Expected/Projected
2015	MP Laskin: converted from coal to natural gas(1)
2017	Minntac Line 6: FIP emission limit compliance date for NO_X(2)
2018	Minntac Line 7: FIP emission limit compliance date for NO_X(2) MP Boswell: Units 1 & 2 retired from service(1)
2019	Hibtac Line 1: FIP emission limit compliance date for NO_X(2) Keetac: FIP emission limit compliance date for NO_X(2) Minntac Line 4 or 5: FIP emission limit compliance date for NO_X(2) Utac Line 1: FIP emission limit compliance date for NO_X(2)
2020	Hibtac Line 2: FIP emission limit compliance date for NO_X(2) Minntac Line 4 or 5: FIP emission limit compliance date for NO_X(2) Minorca: FIP emission limit compliance date for NO_X(2) Utac Line 2: FIP emission limit compliance date for NO_X(2)
2021	Minntac Line: FIP emission limit compliance date for NO_X(2) Hibtac Line 3: FIP emission limit compliance date for NO_X(2)
2023	Xcel: Sherco Unit 2 Retirement(3)
2026	Xcel: Sherco Unit 1 Retirement(3)
2028	Xcel: Allen S. King Plant Retirement(3)
2030	Xcel: Sherco Unit 3 Retirement, Xcel target to emit 80% less carbon by 2030(3)
2050	Xcel: Energy targeting carbon free generation by 2050(3)

(1) Minnesota Power - Integrated Resource Plan 2015-2029
(2) FIP is the regional haze Federal Implementation Plan detailed in 40 CFR 52.1235
(3) Xcel Energy - Upper Midwest Integrated Resource Plan 2020-2034.

4 Visibility Impacts

As described in Section 2.1.3.2, the 2019 Guidance outlines criteria to evaluate when selecting sources that must complete an analysis of emission controls. The 2019 Guidance is clear that a state does not need to evaluate all sources of emissions but "may reasonably select a set of sources for an analysis of control measures" to make progress towards natural visibility.

As described in Section 2.1.3.2.1, the 2019 Guidance provides recommendations on selecting sources by estimating baseline visibility impacts. Three of the options for estimating baseline visibility impacts are analyzed below:

- *Trajectory analyses*[49]
  In general, these analyses consider the wind direction and the location of the Class I areas to identify which sources tend to emit pollutants upwind of Class I areas. The 2019 Guidance says that a state can consider "back trajectories" which "start at the Class I area and go backwards in time to examine the path that emissions took to get to the Class I areas." Section A1.1 of Appendix A, describes the back trajectory analysis and concludes the taconite indurating furnaces were a marginal contributor to the "most impaired" days from 2009 and 2011-2015. The trajectory analysis also indicates many sources other than the taconite facilities were significant contributors to the "most impaired" days.

- *Photochemical modeling*[50]
  The 2019 Guidance says, "states can also use a photochemical model to quantify source or source sector visibility impacts." CAMx modeling was previously conducted to identify visibility impacts in Class I areas from Minnesota taconite facilities from NOx emission reductions. This analysis is summarized in Section A1.2 of Appendix A which concludes the Class I areas near the Iron Range will not experience any observable visibility improvements from NO_X emission reductions suggested by the USEPA in the final Regional Haze FIP for taconite indurating furnaces.

- *Other reasonable techniques*[51]
  In addition to the two analyses described above which estimate the baseline visibility impacts, Section A1.3 of Appendix A evaluates the actual visibility data against the 2009 economic recession impacts on visibility, when taconite facilities curtailed production. This curtailment resulted in a decrease in emissions from the collective group of taconite plant and the regional power production that is needed to operate the plants. The IMPROVE monitoring data during this curtailment period was compared to monitoring data during more typical production at the taconite plants to estimate the taconite facilities' actual (rather than modeled) impact on haze. This analysis concludes "haze levels in BWCA did not, in general, decrease during 2009, and were therefore unaffected by emission reductions associated with the taconite production slowdown. It

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[49] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, Page 13.

[50] Ibid, Page 14.

[51] Ibid, Page 12.

is noteworthy that peak events during mid-2009 in sulfate haze at BWCA when very little taconite production was occurring clearly indicate that minimal haze reduction would likely be associated with taconite plant emission reductions."[52] The report further notes "high nitrate haze days late in 2009 with the taconite plant curtailment that are comparable in magnitude to full taconite production periods in 2008. We also note that after the taconite plants went back to full production in 2010, the haze levels dropped, apparently due to emissions from other sources and/or states."[53]

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[52] AECOM, "Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas," 09/28/2012, Page 10.

[53] Ibid, Page 12.

5 Evaluation of “Effectively Controlled” Source

As described in Section 2.1.3.3, the 2019 Guidance acknowledges that states may forgo requiring facilities to complete the detailed four-factor analysis if the source already has “effective emission control technology in place.”[54] This section demonstrates that the grate-kiln meets USEPA’s BART-required control equipment installation scenario for NO_X and SO_2.

The grate-kiln meets this scenario as an “effectively controlled source” because:

- The grate-kiln is a BART-eligible unit, as determined by Minnesota’s December 2009 Regional Haze Plan, and is regulated under 40 CFR 52.1235 (Approval and Promulgation of Implementation Plans – Subpart Y Minnesota – Regional Haze)
- The grate-kiln has controls and must “meet BART emission limits for the first implementation period”[55] for NO_X and SO_2
- In 2016, EPA promulgated a revised FIP that included, among other things, BART requirements to effectively control NOx and SO2 for the grate kiln[56]

The following sections describe USEPA’s BART determinations, the associated controls that were implemented as BART, and the resulting BART emission limits for NO_X and SO_2.

5.1 NO_X BART-required Controls

In the August 2012 proposed rule FR notice preamble,[57] the USEPA concluded that BART for NO_X from grate-kiln furnaces is low-NO_X burner technology. As part of the evaluation, USEPA eliminated the following emission control measures because they were technically infeasible:

- External and Induced Flue Gas Recirculation Burners due to the high oxygen content of the flue gas;
- Energy Efficiency Projects due to the difficulty with assigning a general potential emission reduction for this emission control measure;
- Alternate Fuels due to the uncertainty of environmental and economic benefits; and

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[54] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, page 22.

[55] Ibid, page 25.

[56] See Federal Register 81, No. 70 (April 12, 2016) 21672. Although the 2012 FIP and the revised 2016 FIP limits for the grate kiln are in litigation, the outcome of that litigation will include BART and what is considered “effectively controlled.” In any case, any resolution of the case, if reached, is subject to public comment. It would be premature, inefficient and inappropriate to unsurp EPA efforts at this juncture.

[57] Federal Register 77, No. 158 (August 15, 2012); 49311. Available at: https://www.govinfo.gov/app/details/FR-2012-08-15/2012-19789

- Selective Catalytic Reduction (SCR) controls because of two SCR vendors declining to bid on NO_x reduction testing at the U.S. Steel Minntac facility.[58]

Because the technical feasibility determinations of the listed control measures have not materially changed since the 2016 final FIP, there are no "further available reasonable controls" for NO_X emissions from taconite indurating furnaces.

The 2016 FIP requires that , Keetac effectively limit NOx emisisons. During the FIP process EPA conducted a robust review of NOx control technologies to determine what was feasible for Keetac to implement. Since the 2016 BART FIP is still in the implementation phase, it is premature and inappropriate to perform another analysis until the requirements of the 2016 FIP have been completed. [59] Thus, the grate-kiln is considered an "effectively controlled source" in accordance with the 2019 Guidance and can reasonably be excluded from the requirement to prepare and submit a four-factor analysis for NO_X. In addition, the BART analysis, which was finalized in 2016, already addressed the elements of the four-factor analysis, which further supports eliminating the grate-kiln from the requirement to submit a four-factor analysis[60].

Table 5-1 NO_X Emission Limits

Unit	Unit ID	NO_X Emission Limit(1) (lb/MMBtu)	Compliance Date(2)
Grate Kiln – Indurator Waste Gas, Phase II	(EQUI 97/EU 030)	1.5	September 2019

(1) However, for any 30, or more, consecutive days when only natural gas is used a limit of 1.2 lbs NOX/MMBtu, based on a 30-day rolling average, shall apply.

(2) Keetac is effectively controlled pursuant to the 2016 revised FIP that is currently under appeal by U. S. Steel. Any resolution of the appeal would indicate whether effective controls are in place at Keetac.

5.2 SO_2 BART-required Controls

In the preamble to the August 2012 proposed FIP[61], the USEPA concluded that BART for SO_2 emissions from the grate-kiln at Keetac is existing controls. As part of the evaluation, USEPA eliminated the following emission control measures because they were technically infeasible:

- Dry Sorbent Injection and Spray Dryer Absorption because the high moisture content of the exhaust would lead to baghouse filter cake saturation and filter plugging

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[58] Ibid, 49323.

[59] Although the 2012 FIP and 2016 FIP revision remain in litigation, the litigation pertains specifically to the determination of BART and what is considered effectively controlled. It would be inapprorrpiate and inefficient to unsurp EPA's determination at this juncture.

[60] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, Page 10.

[61] Federal Register 77, No. 158 (August 15, 2012); 49325. Available at: https://www.govinfo.gov/app/details/FR-2012-08-15/2012-19789

- Alternative Fuels for units burning coal by switching fuels due to the uncertainty of alternative fuel costs, the potential of replacing one visibility impairment pollutant for another, and that BART cannot mandate a fuel switch;

- Coal drying/processing because this requires excess heat source or low-pressure steam, which was not available at Keetac

- Energy Efficiency Projects due to the difficulty with assigning a general potential emission reduction for this emission control measure[62]

In addition, USEPA eliminated Wet Walled Electrostatic Precipitator (WWESP) and secondary (polishing) wet scrubber technologies because they were not cost-effective.[63]

Because the technical feasibility and cost effectiveness determinations of the listed control measures have not materially changed since the 2016 final FIP, there are no "further available reasonable controls" for SO_2 emissions from taconite indurating furnaces.

In accordance with the FIP, Keetac has continued to operate the BART SO_2 control measures and is complying with the FIP SO_2 emission limit[64], as shown in Table 5-2. Thus, the grate-kiln is considered an "effectively controlled source" in accordance with the 2019 Guidance and can reasonably be excluded from the requirement to prepare and submit a four-factor analysis for SO_2. In addition, the BART analysis, which was finalized in 2016, already addressed the elements of the four-factor analysis, which further supports eliminating the grate-kiln from the requirement to submit a four-factor analysis[65].

Table 5-2 SO_2 Emission Limits

Unit	Unit ID	SO_2 Emission Limit (lb/hr)	Compliance Date
Grate Kiln – Indurator Waste Gas, Phase II	(EQUI 97/EU 030)	225	June 8, 2013

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[62] Ibid, 49324.

[63] Ibid.

[64] 40 CFR 52.1235(b)(2)

[65] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, Page 10.

6 Conclusion

The preceding sections of this report support the following conclusions:

- The grate-kiln meets the BART-required control equipment installation scenario and is an "effectively controlled" source for NO_X and SO_2 (see Section 5). As stated in the 2019 Guidance, "it may be reasonable for a state not to select an effectively controlled source."[66] Therefore, it would be reasonable and compliant with USEPA requirements to exclude Keetac from further assessments of additional emission control measures.

- There has been significant progress on visibility improvement in the nearby Class I areas and MPCA's reasonable progress goals should be commensurate with this progress (see Section 3):

    - Visibility has improved at all three monitors (BOWA1, VOYA2, and ISLE1) compared to the baseline period

    - Visibility has been below the URP since 2012

    - The 2018 visibility data is below the URP for 2028

    - Additional emissions reductions have continued throughout the region and are not fully reflected in the available 5-year average (2014-2018) monitoring dataset

    - Additional emission reductions are scheduled to occur in the region prior to 2028, including ongoing transitions of area EGUs from coal to natural gas or renewable sources, as well as the installation of low-NO_X burners throughout the taconite industry

- The grate-kiln does not materially impact visibility from a theoretical (modeling) and empirical (actual visibility data) basis and should not be required to assess additional emission control measures. (see Section 4).

The combination of these factors provides sufficient justification for MPCA to justify to USEPA Keetac's exclusion from the group of sources required to conduct a four-factor analysis for this implementation period. Thus, the MPCA should withdraw its request for a four-factor analysis for the grate-kiln.

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[66] Ibid, Page 22

Appendices

Appendix A

Visibility Impacts

A1 Visibility Impacts

A1.1 Trajectory Analysis

The August 2019 U.S. EPA Guidance ("2019 Guidance" or "the Guidance")[1] says that the state may use a "reasonable surrogate metrics of visibility impacts" when selecting sources to conduct an four-factor analysis and cites trajectory analysis as an example of a reasonable technique. This analysis considers reverse trajectories, as provided on MPCA's website[2], to determine the frequency that the trajectories on the "most impaired days"[3] overlapped with a specific area of influence (AOI) on the Iron Range. Data from 2011-2015 were analyzed as this was the most recent five-year period where the taconite facilities were operating under typical production rates.

A particle trajectory analysis is an analysis of the transport path of a particular air mass, including the associated particles within the air mass, to see if the air mass traveled over certain locations from specific source locations. The MPCA tracks visibility via the IMPROVE (Interagency Monitoring of Protected Visual Environments) monitoring sites at Boundary Waters Canoe Area Wilderness (BWCA), Voyageurs National Park (Voyageurs) and Isle Royale National Park (Isle Royale).[4] MPCA's website includes a tool which analyzes reverse trajectories from BWCA and Voyageurs for the "most impaired days" and the clearest days for 2007-2016 to show the regional influence on visibility. The reverse trajectories included in the MPCA tool were developed using the NOAA Hysplit model.[5] The trajectories consist of a single back trajectory for each day of interest, beginning at 18:00 and running back 48 hours with a starting height of 10 meters.

The MPCA Hysplit reverse trajectories from the "most impaired days" were analyzed to identify whether trajectories overlapped with an AOI from certain taconite facilities on the Iron Range. In order to be conservative, Barr estimated an "uncertainty region" for each trajectory based on 20% of the distance traveled for every 10km along the trajectory pathway. This method is consistent with other scientific studies analyzing reverse trajectories and trajectories associated with the NOAA Hysplit model (Stohl - 1998[6], Draxler - 1992[7], Draxler and Hess - 1998[8]). For the purpose of this analysis, the Iron Range AOI was defined as a line connecting the stack at the U. S. Steel Keetac facility with the stack at the ArcelorMittal Minorca Mine and a 3-mile radius surrounding the line. This analysis considers how often the MPCA reverse trajectories overlap the Iron Range AOI on the "most impaired days" to quantitatively determine if the emissions from the Iron Range may have been a contributor to impaired visibility. Attachment 1 to Appendix A includes tables with the annual and seasonal results of this analysis as well as two example figures showing trajectories that cross, and do not cross, the Iron Range AOI.

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[1] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[2] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Regionalinfluence

[3] "Most impaired days" is the 20% most anthropogenically impaired days on an annual basis, measured in deciviews (dv), as provided on MPCA's website.

[4] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Regionalinfluence

[5] https://www.arl.noaa.gov/hysplit/hysplit/

[6] http://www.kenrahn.com/DustClub/Articles/Stohl%201998%20Trajectories.pdf

[7] https://www.arl.noaa.gov/documents/reports/ARL%20TM-195.pdf

[8] https://www.arl.noaa.gov/documents/reports/MetMag.pdf

As shown in Figure A1 and Figure A2, reverse trajectories from BWCA and Voyageurs in 2011-2015 did not overlap the Iron Range AOI on 62-80%, and 56-71% of "most impaired days", respectively. This means the taconite industry did not influence visibility at BWCA and Voyageurs on the majority of "most impaired days" and suggest that sources other than the taconite facilities are larger contributors to visibility impairment at these sites. Furthermore, the origins of many of the "most impaired day" reverse trajectories are beyond the Iron Range AOI and thus have influences, depending on the trajectory, from other sources (e.g., Boswell Energy Center, Sherburne County Generating Station) or cities such as Duluth, St. Cloud, the Twin Cities, and Rochester as shown in Figure A3.

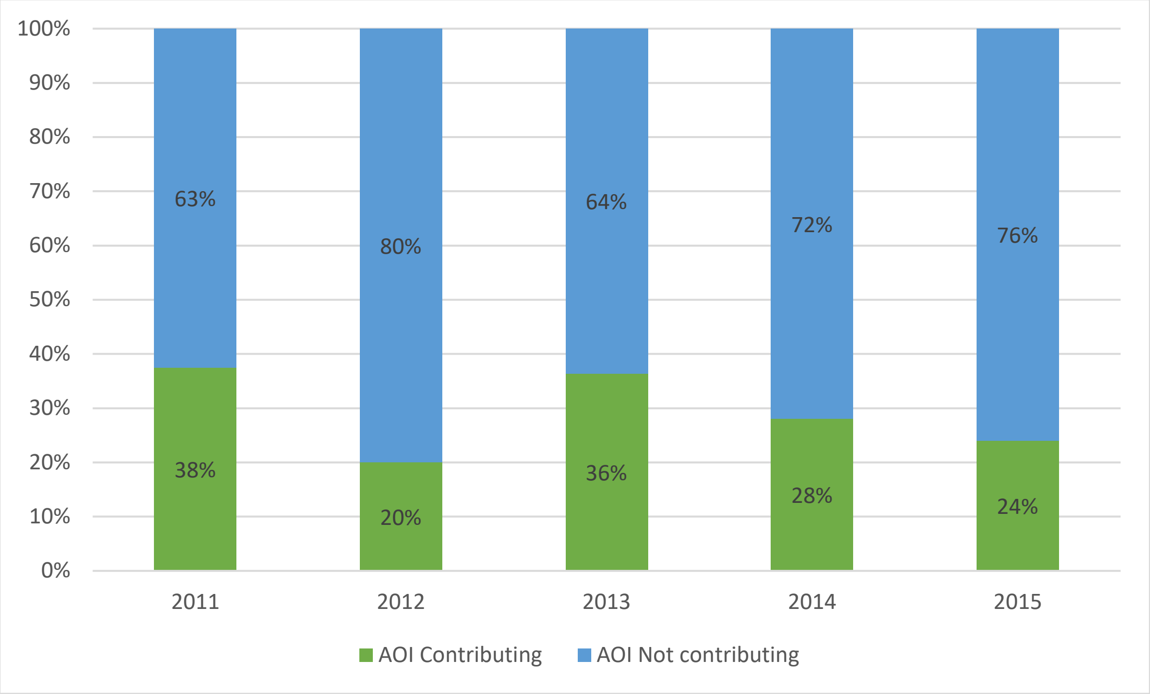

Figure A1 Proportion of "most impaired days" Iron Range AOI was Contributing or Not Contributing to Visibility at BWCA

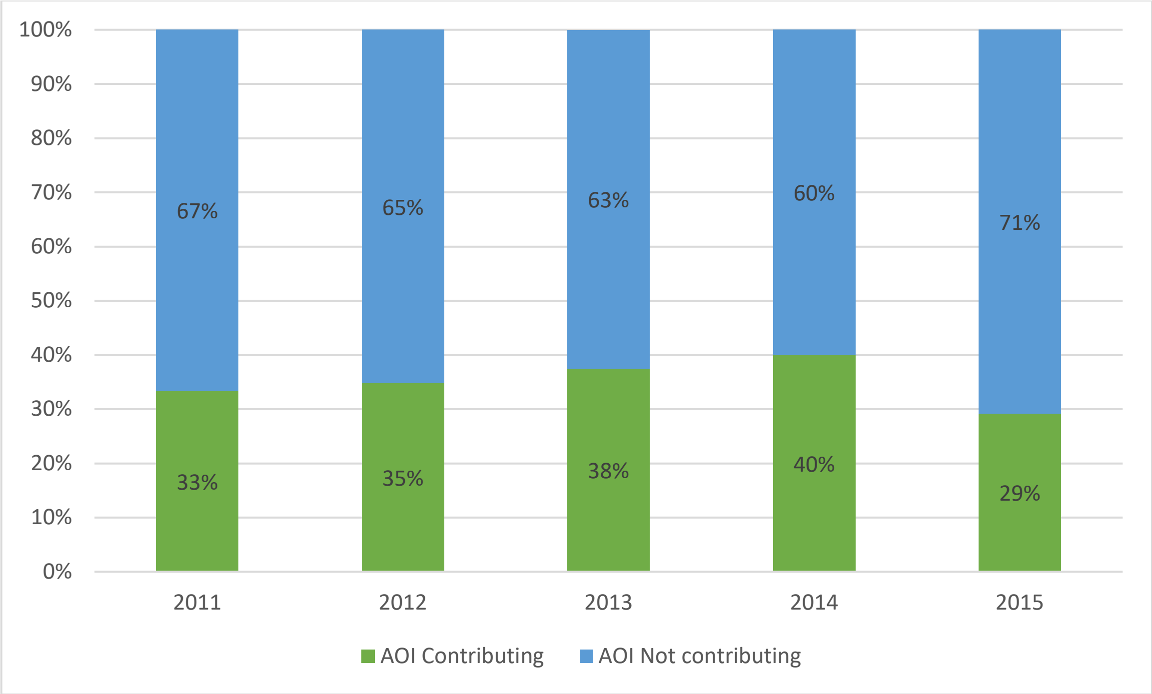

Figure A2 Proportion of "most impaired days" Iron Range AOI was Contributing or Not Contributing to Visibility at Voyageurs

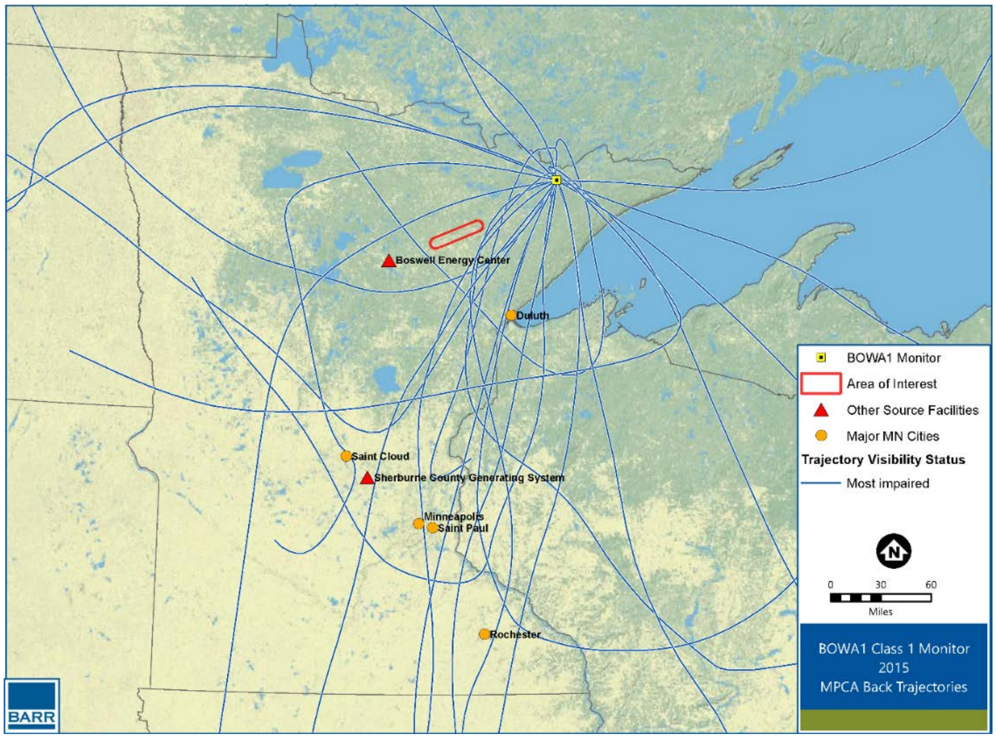

Figure A3 Reverse Trajectories and Other Sources Influencing Visibility at BWCA[9]

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[9] Source: ArcGIS 10.7.1, 2020-05-14 13:31 File: I:\Client\US_Steel\Trajectory_Analysis\Maps\Trajectory_Routes_BOWA1_2015_zoom.mxd User: ADS

A1.2 Photochemical Modeling

As part of the requirement to determine the sources to include and how to determine the potential visibility improvements to consider as part of this selection, the 2019 Guidance provided some specific guidance on the use of current and previous photochemical modeling analyses (emphasis added):

> *"A state opting to select a set of sources to analyze must reasonably choose factors and apply them in a reasonable way given the statutory requirement to make reasonable progress toward natural visibility. Factors could include but are not limited to baseline source emissions, baseline source visibility impacts (or a surrogate metric for the impacts), [and] the in-place emission control measures…"*[10]

The Guidance lists options for the evaluation of source visibility impacts from least rigorous to most rigorous as: (1) emissions divided by distance (Q/d), (2) trajectory analyses, (3) residence time analyses, and (4) photochemical modeling (zero-out and/or source apportionment). It appears that MPCA selected the least rigorous (Q/d) for inclusion of sources in the four-factor analyses. The most rigorous is described below (emphases added):

> ***"Photochemical modeling****. In addition to these non-modeling techniques, states can also use a photochemical model to quantify source or source sector visibility impacts. In 2017, EPA finalized revisions to 40 CFR Part 51 Appendix W, Guideline on Air Quality Models. As part of that action, EPA stated that photochemical grid models should be the generally preferred approach for estimating source impacts on secondary PM concentrations. The existing SIP Modeling Guidance provides recommendations on model setup, including selecting air quality models, meteorological modeling, episode selection, the size of the modeling domain, the grid size and number of vertical layers, and evaluating model performance. EPA Regional offices are available to provide an informal review of a modeling protocol before a state or multijurisdictional organization begins the modeling.*
>
> *The SIP Modeling Guidance focuses on the process for calculating RPGs using a photochemical grid model. The SIP Modeling Guidance does not specifically discuss using photochemical modeling outputs for estimating daily light extinction impacts for a single source or source sector. However, the approach on which the SIP Modeling Guidance is based can also be applied to a specific source or set of sources. The first step in doing this is to estimate the impact of the source or set of sources on daily concentrations of PM species.*
>
> *The simplest approach to quantifying daily PM species impacts with a photochemical grid model is to perform brute force "zero-out" model runs, which involves at least two model runs: one "baseline" run with all emissions and one run with emissions of the source(s) of interest removed from the baseline simulation. The difference between these simulations provides an estimate of the PM species impact of the emissions from the source(s).*

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[10] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, Page 10

> *An alternative approach to quantifying daily PM species impacts is photochemical source apportionment. Some photochemical models have been developed with a photochemical source apportionment capability, which tracks emissions from specific sources or groups of sources and/or source regions through chemical transformation, transport, and deposition processes to estimate the apportionment of predicted $PM_{2.5}$ species concentrations. Source apportionment can "tag" and track emissions sources by any combination of region and sector, or by individual source. For example, PM species impacts can be tracked from any particular source category in the U.S., or from individual states or counties. Individual point sources can also be tracked."*[11]

As part of the previous regional haze planning evaluation, and to provide comments on USEPA's disapproval of the Minnesota SIP and the subsequent Regional Haze Federal Implementation Plan (FIP) (Docket EPA-R05-OAR-2010-0954 & EPA-R05-OAR-2010-0037), Barr completed photochemical modeling of ArcelorMittal and Cleveland-Cliffs' taconite operations in 2013 using CAMx source apportionment (see Attachment 2). The basis of the CAMx modeling was the Minnesota modeling analyses, which were completed as part of the regional haze SIP, including Plume in Grid (PiG) evaluations of sources included in BART analyses. This modeling included 2002 and 2005 baseline periods with projected emissions to 2018 (the first implementation planning period for the regional haze SIPs and a strong surrogate for the baseline period for the 2nd planning period). Therefore, the analysis completed is one of the best available surrogates for the potential visibility impacts from the sources that were "tagged" as part of those comments. It is important to note that the MPCA modeling analysis did not require any additional controls for taconite sources under BART. Further, the CAMx modeling that Barr conducted showed that the impact from NO_X emissions from the Minnesota taconite facilities had very limited visibility impacts on the three Upper Midwest Class I areas.

Specifically, the results from executing CAMx concluded that the Class I areas near the Iron Range will not experience any observable visibility improvements from NO_X emission reductions that were suggested by the USEPA in the final Regional Haze FIP for taconite indurating furnaces. The modeling analysis showed that the scalar method that USEPA used to forecast the visibility improvements was inadequate to determine the visibility impacts from taconite sources. The CAMx predicted impacts for every furnace line were at or below the de minimis threshold for visibility improvement (0.1 delta-dV).

In addition, the large amount of potential NO_X emission reductions from the FIP baseline to the final FIP (>10,000 tons per year from modeled Minnesota taconite operations) was not impactful from a visibility modeling perspective. This finding provides specific source modeling evidence that additional NOx emission reductions from any or all of the taconite operations are likely not helpful for visibility improvements at the Upper Midwest Class I areas. This is particularly true given the current amount of NO_X emissions generated by the taconite sources as part of the current baseline.

The 2019 Guidance addresses how states should select sources that must conduct a four-factor analysis. The RHR suggests that states can use a photochemical model to quantify facility or even stack visibility impacts. The previous CAMx modeling was conducted for the 2018 projection year and the results are

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[11] Ibid, Page 14.

especially helpful in the current visibility impact assessment to determine if the EPA’s four-factor applicability analysis is necessary. Aside from the fact that the NO_X reductions of taconite indurating furnaces do not result in visibility improvements, the emissions from these sources have been trending downward from 2013 to present. These reductions are related to the recent installation of low NO_X burners on the taconite indurating furnaces and the overall Minnesota state reductions from the switch from coal- to natural gas-fired power plants. Thus, it is reasonable to conclude that additional emission reductions beyond the FIP limits of the taconite indurating furnaces will not be beneficial to improve visibility at the Class 1 areas nor is it anticipated to be necessary to reach the 2028 target visibility goal.

In summary, the exclusion of the taconite sources from the four factor analysis for NOx is reasonable, supported by the previous CAMx modeling performed for 2018 projected emissions that conclude additional emission reductions beyond the FIP limits of the taconite indurating furnaces will not be beneficial to improve visibility, and in line with the Guidance regarding selection of sources based on previous modeling analyses and the additional NO_X reductions anticipated in Minnesota.

A1.3 Visibility Impacts During 2009 Recession

During the economic recession in 2009, the Iron Range experienced a reduction in taconite production. This resulted in a decrease in emissions from the collective group of taconite plants and the regional power production that is needed to operate the plants. The IMPROVE monitoring data during this period was compared to monitoring data during more typical production at the taconite plants to estimate the actual (rather than modeled) impact on haze. This assessment was completed in 2012 (herein termed as “the 2012 analysis”) and submitted by Cliffs as a comment to proposed Minnesota regional haze requirements (Docket: EPA-R05-OAR-2010-0037), included as Attachment 3. The 2012 analysis focused on the likely visibility impact of NO_X emissions from the taconite indurating furnaces.

Observations noted in the 2012 analysis highlighted that concentrations of visibility impairing pollutants do not appear to closely track with actual emissions from taconite facilities. For example, nitrate (NO_3) is a component of haze associated with NO_X emissions that are emitted from a number of sources, including the indurating furnaces at the taconite facilities. As shown in Figure A4, the 2012 analysis compared taconite facility production rates to nitrate concentration for 1994-2010 at the BWCA monitor. The 2012 analysis concludes that “haze levels in BWCA did not, in general, decrease during 2009, and were therefore unaffected by emission reductions associated with the taconite production slowdown. It is noteworthy that peak events during mid-2009 in sulfate haze at BWCA when very little taconite production was occurring clearly indicate that minimal haze reduction would likely be associated with taconite plant emission reductions.”[12] The report further notes that “high nitrate haze days late in 2009 with the taconite plant curtailment that are comparable in magnitude to full taconite production periods in 2008. We also note that after the taconite plants went back to full production in 2010, the haze levels dropped, apparently due to emissions from other sources and/or states.”[13]

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[12] AECOM, “Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas,” 09/28/2012, Page 10.

[13] Ibid, Page 12.

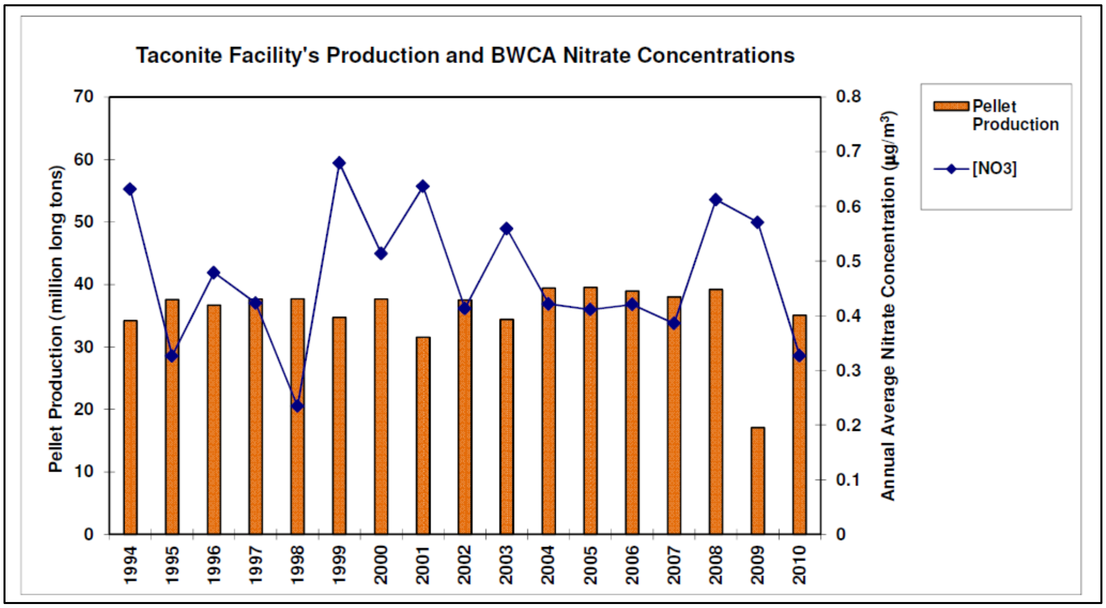

Figure A4 Minnesota Taconite Production and BWCA Nitrate Concentrations 1994-2010 [14]

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[14] AECOM, "Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas," 09/28/2012, Page 9

Attachments

Attachment 1

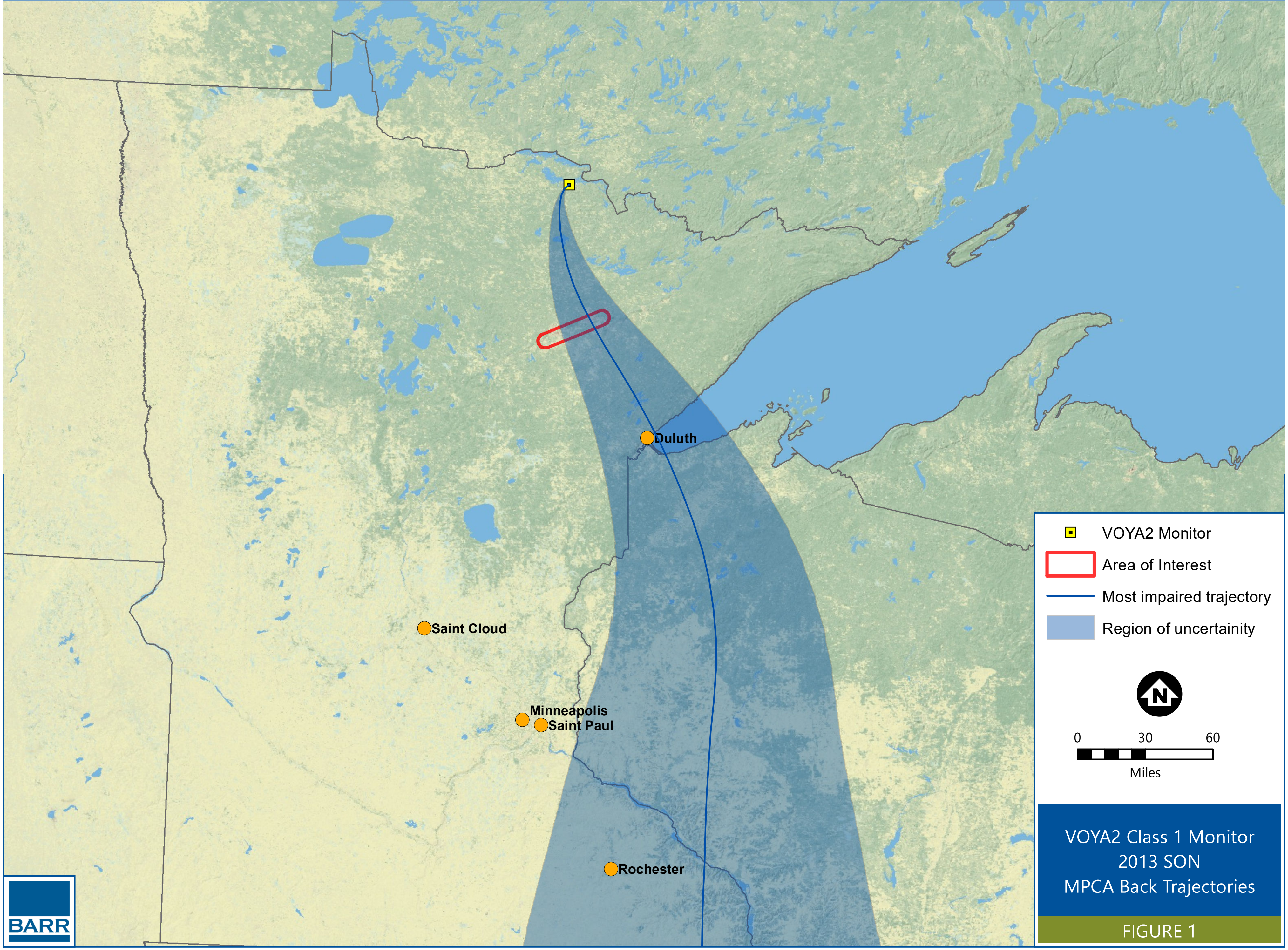
Trajectory Analysis Summary Tables and Reverse Trajectory Example Figures

Table A1 Results from MPCA Hysplit Trajectories for the BOWA1 Monitor

Year	Time Period	Most Impaired Days	"Most Impaired" Trajectories With Uncertainty Region Crossing Iron Range AOI (%)
2011	Winter (DJF)	9	44%
	Spring (MAM)	8	38%
	Summer (JJA)	4	0%
	Fall (SON)	3	67%
	Total	**24**	**38%**
2012	Winter (DJF)	13	23%
	Spring (MAM)	4	0%
	Summer (JJA)	1	0%
	Fall (SON)	7	29%
	Total	**25**	**20%**
2013	Winter (DJF)	9	44%
	Spring (MAM)	5	60%
	Summer (JJA)	3	0%
	Fall (SON)	5	20%
	Total	**22**	**36%**
2014	Winter (DJF)	9	33%
	Spring (MAM)	8	13%
	Summer (JJA)	2	0%
	Fall (SON)	6	50%
	Total	**25**	**28%**
2015	Winter (DJF)	13	15%
	Spring (MAM)	3	67%
	Summer (JJA)	1	0%
	Fall (SON)	8	25%
	Total	**25**	**24%**

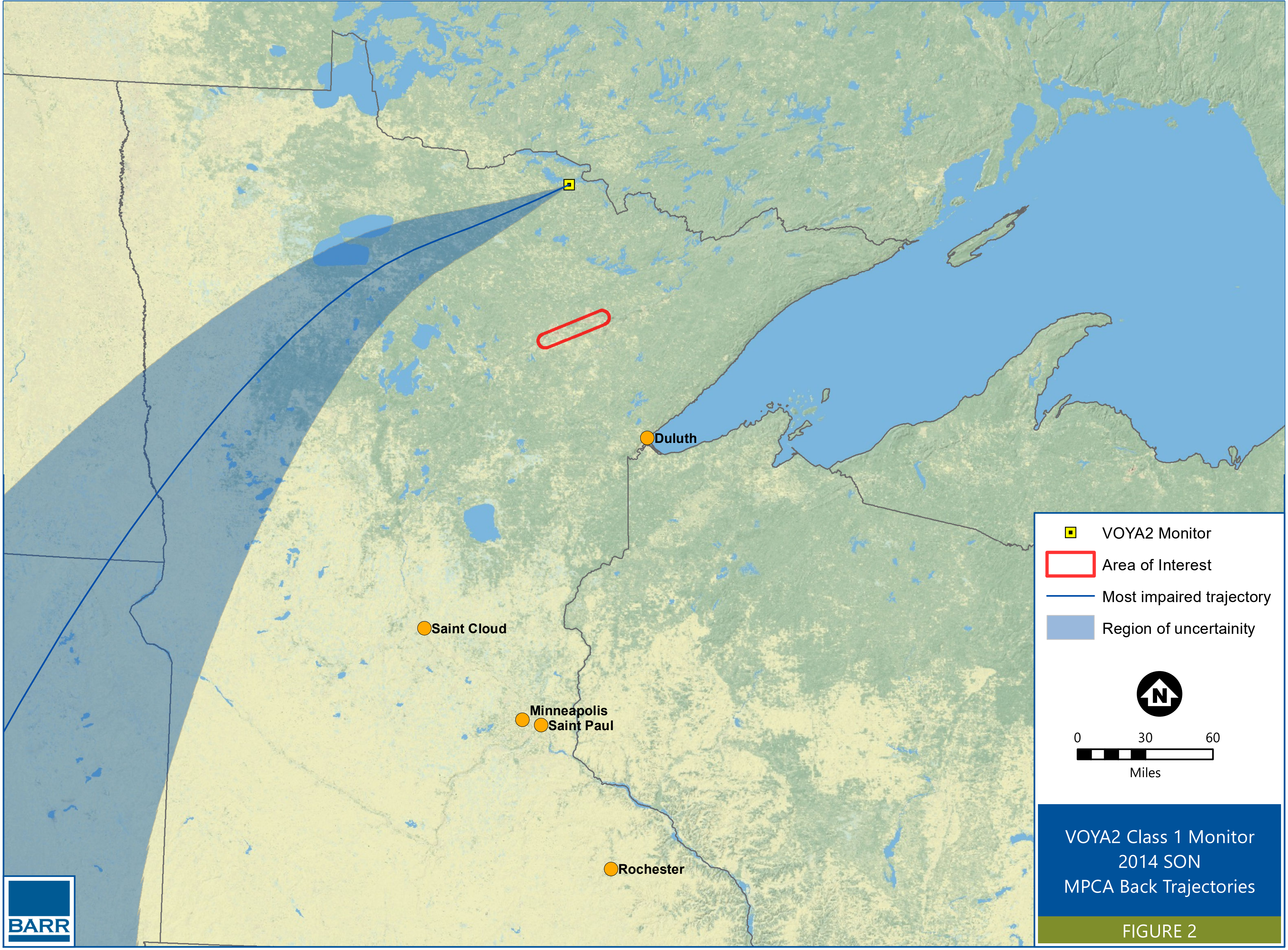
Table A2 Results from MPCA Hysplit Trajectories for the VOYA2 Monitor

Year	Months	Most Impaired Days	"Most Impaired" Trajectories With Uncertainty Region Crossing Iron Range AOI (%)
2011	Winter (DJF)	8	38%
	Spring (MAM)	7	29%
	Summer (JJA)	4	25%
	Fall (SON)	5	40%
	Total	**24**	**33%**
2012	Winter (DJF)	13	23%
	Spring (MAM)	3	67%
	Summer (JJA)	0	0%
	Fall (SON)	7	43%
	Total	**23**	**35%**
2013	Winter (DJF)	9	22%
	Spring (MAM)	5	40%
	Summer (JJA)	3	0%
	Fall (SON)	7	71%
	Total	**24**	**38%**
2014	Winter (DJF)	10	50%
	Spring (MAM)	7	43%
	Summer (JJA)	2	0%
	Fall (SON)	6	33%
	Total	**25**	**40%**
2015	Winter (DJF)	14	21%
	Spring (MAM)	4	50%
	Summer (JJA)	1	100%
	Fall (SON)	5	20%
	Total	**24**	**29%**



VOYA2 Class 1 Monitor
2013 SON
MPCA Back Trajectories

FIGURE 1



VOYA2 Class 1 Monitor
2014 SON
MPCA Back Trajectories

FIGURE 2

Attachment 2

CAM$_X$ Modeling Report

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engineering and environmental consultants
BARR

Technical Memorandum

From: Barr Engineering

Subject: Summary of Comprehensive Air Quality Model with Extensions (CAM_X) Analyses Performed to Evaluate the EPA Regional Haze Federal Implementation Plan for Taconite Facilities

Date: March 6, 2013

Executive Summary

Barr Engineering conducted air modeling to predict the impact of NO_X reductions from certain taconite furnaces in Minnesota and Michigan. Using EPA's preferred Comprehensive Air Quality Model with Extensions (CAM_X), the model results demonstrate that the Class I areas near these furnaces will experience no perceptible visibility improvements from NO_X emission reductions envisioned by EPA in the recent Regional Haze FIP at the furnaces. The analysis strongly suggests that the scalar method that EPA used to predict visibility improvements under significant time constraints was an inadequate substitute for CAM_X, as EPA's approach over-predicted visibility impacts by factors of ten to sixty when compared with the proper CAM_X analysis. The basis for EPA's technical analysis of the visibility improvements for their proposed emission changes must therefore be dismissed as unsupportable, and the results of this analysis should be used instead. This analysis ultimately supports the conclusions of the States of Michigan and Minnesota in their Regional Haze SIPs, that experimental low NO_X burner retrofits did not meet the criteria for BART. The imperceptible visibility improvements associated with NO_X reductions from these furnaces cannot justify the cost or the operational risks of changing burners.

Discussion

This memorandum provides a summary of the methodology and results from photochemical modeling analyses conducted to support the Cliffs Natural Resources (CNR) and Arcelor Mittal (Arcelor) response to the United States Environmental Protection Agency (EPA) final Regional Haze Federal Implementation Plan (FIP) for taconite facilities. Further, it provides a basis for comment on the proposed disapproval of the Minnesota and Michigan State Implementation Plans for taconite Best Available Retrofit Technology (BART) at the above mentioned facilities. This memorandum also includes an appendix with a summary of the BART visibility improvement requirements and a review of

the EPA "scalar" method in the proposed and final FIP for determining the visibility improvement from taconite emission reductions. Further, the memorandum contrasts EPA's findings with the modeling analysis conducted and previously requested by CNR as part of its comments on the proposed FIP. The modeling evaluated emission differences at all the CNR and Arcelor taconite facilities.

Ultimately, this memorandum provides results demonstrating no perceptible visibility improvement from the NO_X emission reductions proposed and subsequently finalized by EPA in the Regional Haze FIP for the CNR and Arcelor facilities.

I. CAM_X Modeling Methodology

The methodology utilized by Barr to complete the CAM_X modeling was identical to the methods utilized by the Minnesota Pollution Control Agency (MPCA) in performing the 2002 and 2005 baseline and BART SIP modeling in 2009. This included the use of the CAM_X modeling system (CAM_X v5.01 - air quality model, MM5 - meteorological model, and EMS-2003 - emissions model) with meteorological data, low-level emission data, initial and boundary condition files, and other input files received directly from MPCA. Modifications to the emissions within the elevated point source input files used by MPCA were accomplished for the taconite facility furnace stacks to reflect the differences in the FIP baseline and final FIP control scenarios. In addition, the CAM_X run scripts used to execute the model were provided by MPCA for each of the four calendar quarters (Jan-Mar, Apr-Jun, Jul-Sep, and Oct-Dec) along with the post-processing scripts used to estimate the visibility impacts for each scenario.

An important fact is that the results from the MPCA modeling for Minnesota's regional haze State Implementation Plan (SIP) development were also utilized by EPA in the "scalar" method proposed in the FIP. These results were subsequently defended by EPA in the final FIP stating "EPA stands by the results of its ratio approach and believes that it produced reasonable results for the sources examined."[1] The methods utilized by MPCA represent not only an EPA-approved approach for SIP submittal, but also formed the basis of the visibility determinations made by EPA in the proposed and final FIP. However, since EPA did not conduct its own modeling and provided only the "scalar" results, there are substantial and inherent flaws in the EPA-estimated visibility impacts. These flaws are detailed in Appendix A to this memorandum which includes a review of the EPA scalar approach. Since the modeling reported here used identical methods to the MPCA analyses, it is consistent with the underlying data that was used in

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[1] Federal Register, Volume 78, Number 25, page 8721, February 6, 2013

the EPA FIP method for estimating visibility impact. Further, this modeling provides specific technical analyses regarding the estimated effects of CNR and Arcelor taconite unit emission reductions in the final FIP on the relevant Class I areas. To effectively evaluate the impact of NOx reductions on regional haze, this level of analyses should have been conducted by EPA before publishing and finalizing the taconite BART FIP for Minnesota and Michigan.

Nonetheless, the first step in any photochemical modeling exercise is to ensure that the modeling results can be replicated to ensure no errors in the data transfer or modeling setup. Barr worked with MPCA to obtain the 2002 and 2005 modeling input files, run scripts, and post-processing files to allow for the validation of the Barr modeling system. To be clear, the modeling comparison scenario used the exact same files provided by MPCA with no adjustments. Given the length of time required to complete the modeling analyses, this step focused on the 2002 dataset and evaluated the results from the 2002 baseline and 2002 Minnesota BART SIP. The information provided by MPCA to complete this comparison was contained in the document: "Visibility Improvement Analysis of Controls Implemented due to BART Determinations on Emission Units Subject-to-BART", October 23, 2009. The results of the comparison are contained in Appendix B: Barr and MPCA CAM_X Modeling Comparison of Results. As expected with any photochemical model comparison running four different quarterly simulations using two different computer systems and Fortran compilers, there are insignificant differences in the end values. The overall comparison of the results was very favorable and showed excellent agreement between the four modeled datasets (i.e. 2002 baseline and 2002 BART SIP, each from MPCA and Barr).

After successful confirmation of the consistency check of the Barr modeling system to the MPCA system, the modeling focused on the specific emission changes in the MPCA elevated point source files. As with most regional modeling applications, there were 36 "core" point source files for each scenario. This set corresponds to three files per month (Saturday, Sunday, and weekday) for all twelve months. Emission information from each file was extracted for all the CNR and Arcelor taconite facilities in Minnesota to confirm the emission totals used by MPCA in the SIP baseline and BART SIP control scenarios. The emission summary data for each unit matched the summary tables within the MPCA BART SIP modeling. Also, the emission sources from Tilden Mining Company in Michigan were identified and information extracted to allow for the same type of modeling as was conducted for the Minnesota facilities.

The next step was to include United Taconite Line 1 in the baseline and FIP modeling files. Line 1 was not originally included in the MPCA modeling because it was not operational in the 2002 base year.

Therefore, the information for that source was obtained from MPCA-provided 2018 elevated point source files and incorporated into the 36 core elevated point source files. This allowed all the CNR and Arcelor furnace lines within the FIP to be evaluated as part of this modeling analysis. To that end, each CNR and Arcelor BART-eligible source was specifically identified and labeled for processing to track modeled impacts using plume-in-grid treatment and the Particulate Source Apportionment Technology (PSAT) contained within CAM_X (including Tilden Mining). A list of the sources that were included in the specific PSAT groups can be found in Appendix C: CAM_X PSAT Source List.

As part of the identification and labeling process, the MPCA BART SIP elevated point source files were converted from binary input files to ascii text files using the BIN2ASC program. (NOTE: by using the BART SIP point source files, all other Minnesota BART-eligible sources were included in this modeling exercise using their BART SIP emissions to isolate the impacts of the CNR and Arcelor units.) Then, a Fortran90 program was developed to adjust the hourly emissions from each applicable source to correspond to the sum of annual emissions within each of the following scenarios: EPA FIP baseline and EPA final FIP. It is important to note that the temporal factors for each source were not modified from the original MPCA-provided inventory files (i.e. no changes to the monthly or day-of-week factors). This emission approach allowed for the exact set of emissions within each of the scenarios to be modeled. After the emissions within the text file were adjusted, the emissions were checked for accuracy. Then, each file was converted back to binary input from ASCII text using the ASC2BIN program. The emission summary for each unit/scenario combination is contained in Appendix D: Summary of CAM_X Elevated Point Source Emissions. Appendix D also provides a reference list for the emissions from the proposed FIP, Final FIP (where applicable), and calculation methodology where EPA did not provide sufficient information to calculate emissions. Table 1 contains a facility summary for all taconite furnaces under each scenario.

As stated previously, one of the outcomes of these analyses was the comparison of EPA's scalar approach to specific photochemical modeling using EPA's emission reduction assumptions within the FIP rulemakings. These modeling analyses make no judgment as to the achievability of these emission reductions. CNR and Arcelor dispute that these NOx reductions are achievable for all furnaces. These modeling analyses are, therefore, a conservative evaluation of EPA's predicted NOx reductions – not the actual NOx reductions achievable by the application of BART.

Table 1: Facility Taconite Furnace Emission Summary

Facility	FIP Baseline (TPY)		Final FIP (TPY)		Difference (TPY)	
	SO2	NOx	SO2	NOx	SO2	NOx
Arcelor Mittal	179	3,639	179	1,092	0	2,547
Hibbing Taconite	570	6,888	570	2,066	0	4,821
United Taconite	4,043	5,330	1,969	1,599	2,074	3,731
Northshore Mining	73	764	73	229	0	535
Tilden Mining	1,153	4,613	231	1,384	922	3,229
Total	**6,018**	**21,233**	**3,022**	**6,370**	**2,996**	**14,863**

Two other issues should be noted here.

1. The first is the nested 12-km modeling domain selected by MPCA (illustrated in Figure 1) along with the specific “receptors” used for identification of the relevant Isle Royale Class I area and their use for determination of impacts from Tilden Mining Company. The Tilden Mining source was not included in the MPCA fine grid as it was not part of the Minnesota SIP. However, the elevated point source file includes the sources in the entire 36 km domain (including Tilden). As such, the Tilden emissions were available for estimation of specific visibility impacts. The receptors selected by MPCA only included the western half of the Isle Royale Class I area because that is the portion of the area closest to the Minnesota sources. However, the size of the grid cells (e.g. 12 and 36 km) provides a large number of potential receptors at all the Class I areas and little variation among receptors is expected at the distance between Tilden and Isle Royale. Thus, the modeling data should adequately represent the visibility impact at the entire Isle Royale Class I area.

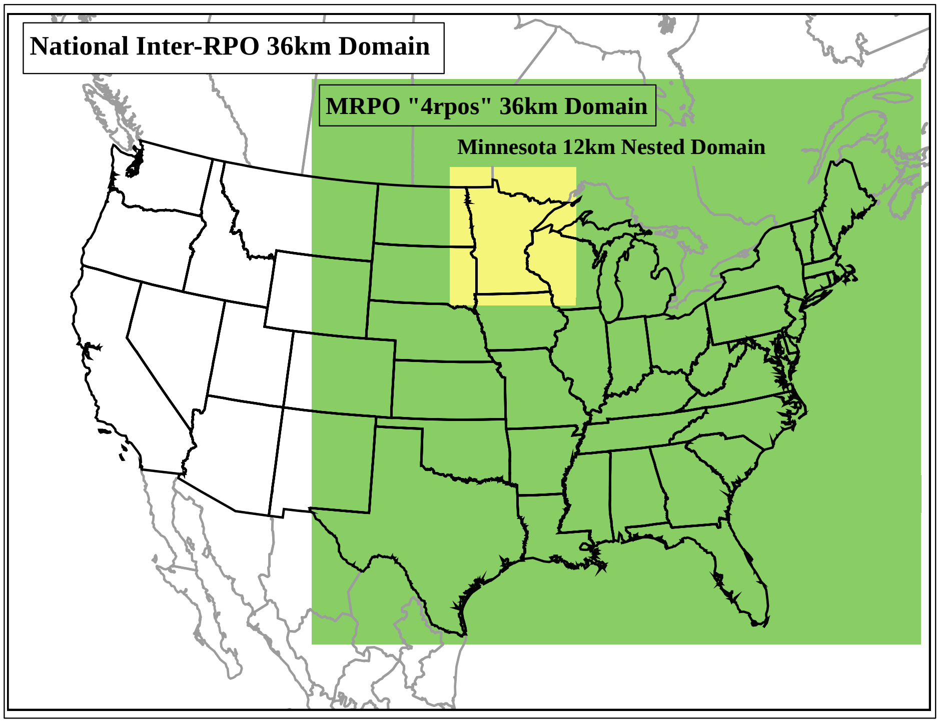

Figure 1. MPCA Modeling Domain

2. The second issue is the inconsistency between the emission reduction estimates used by EPA in the calculation of their scalar visibility benefits (i.e. Tables V-C of the proposed and final FIP) and the emission reductions calculated in the facility-specific sections of the proposed FIP. EPA's flawed calculation methodology did not use the appropriate emission reductions. In order to calculate the emissions for evaluation of the final FIP in the CAM_X modeling, Barr was left with utilizing the limited information provided in the proposed and final FIP rulemaking. The lack of information and the errors and inconsistencies within the dataset were highlighted in the information request on January 31, 2013 to EPA (included in Appendix E). As of the time of this memorandum, no response by EPA has been received by Barr. Further, given the time required to complete the modeling, assumptions were made that were conservative to calculate the FIP emissions. For example, the final FIP references a 65% NO_X reduction from Tilden Mining Company due to the switch to natural gas firing, but that was not consistent with the other gas-fired kilns (proposed FIP reduction was 70% with the same 1.2 lb NO_X/MMBTU emission limit). Therefore, to provide the maximum emission reductions, the 70% control was utilized for all the CNR and Arcelor taconite furnaces.

II. Summary of CAM_X Results

As mentioned above, the CAM_X model was executed for each calendar quarter of 2002 and 2005 using the adjusted emissions for each scenario. The results were then post-processed to calculate visibility impacts for each scenario in deciviews (dV). All these results are provided in Appendix F: CAM_X Results by Facility. For the purposes of this memorandum, the following tables compare EPA's estimates of annual average impact contained within the proposed FIP with the results generated by the CAM_X modeling for this project on a facility by facility basis. The first three facilities contain emission reductions for only NO_X: Arcelor Mittal, Hibbing Taconite, and Northshore Mining. These results are summarized in Tables 2-4. United Taconite and Tilden Mining, which have both SO_2 and NO_X emission reductions, have result comparisons that require additional discussion.

The context of these results includes the following visibility impact thresholds:

0.5 dV impact is the BART eligibility and contribute to visibility impairment threshold (i.e. if a facility has less than 0.5 dV impact in the baseline, no BART is required)[2],

1.0 dV difference is the presumed human perceptible level for visibility improvement, and

0.1 dV difference was defined by other agencies, such as the northeastern states MANE-VU Regional Planning Organization[3] as the degree of visibility improvement that is too low to justify additional emission controls. In addition, EPA's Regional Haze Rule mentions[4] that "no degradation" to visibility would be "defined as less than a 0.1 deciview increase."

The first two columns within Tables 2-4 and 6-8 provide the difference in 98th percentile visibility improvement from the baseline to the FIP control emissions, while the third column provides a measure of over-estimation when using the EPA scalar approach (i.e. % Over Estimation by EPA = EPA Estimated Difference / CAM_X Modeled Difference).

Table 2: Arcelor Mittal Visibility Impact Comparison

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[2] 40 CFR Part 51, Appendix Y – Guidelines for BART Determinations under the Regional Haze Rule.

[3] As documented by various states; see, for example, www.mass.gov/dep/air/priorities/hazebart.doc, which indicates a visibility impact of less than 0.1 delta-dv is considered "de minimis".

[4] 64 FR 35730.

Class I Area	EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	1.7		0.1		1500%
Voyageurs	0.9		0.09		1000%
Isle Royale	1.1		0.03		3700%

Table 3: Hibbing Taconite Visibility Impact Comparison

Class I Area	EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	3.2		0.19		1700%
Voyageurs	1.7		0.11		1500%
Isle Royale	2.1		0.04		5300%

Table 4: Northshore Mining Visibility Impact Comparison

Class I Area	EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	0.6		0.01		6000%
Voyageurs	0.3		0.01		3000%
Isle Royale	0.4		0.01		4000%

As pointed out in the previous comments on this proposed FIP, these results clearly demonstrate that the NOx reductions proposed in the FIP will not provide a perceptible visibility improvement. Additionally, it demonstrates that the EPA methodology using scalars severely overestimated the visibility impact from NO_X emission reductions at these taconite furnaces in northeast Minnesota. Even when using maximum emission reductions from EPA's baseline, the EPA estimates grossly over predicted the potential dV improvement by over <u>10 times</u> the predicted 98th percentile visibility improvement in all cases for the Arcelor Mittal, Hibbing Taconite, and Northshore Mining facilities. The maximum 98th percentile visibility improvement predicted by the source specific tracking for any one line was 0.1 dV (Arcelor Mittal Line 1 on Boundary Waters). The minimum 98th percentile visibility improvement was 0.01 dV (Northshore Mining on Isle Royale). Further, the results presented in Table 5 for the individual furnace line impacts at Hibbing Taconite illustrate de minimis visibility improvement at all the Class I areas evaluated.

Table 5: Hibbing Taconite Line-Specific Visibility Impacts

Class I Area	Furnace Line		CAM_X Modeled Difference 98% dV
Boundary Waters	Line 1		0.04
	Line 2		0.05
	Line 3		0.08
Voyageurs	Line 1		0.03
	Line 2		0.04
	Line 3		0.04
Isle Royale	Line 1		0.01
	Line 2		0.01
	Line 3		0.01

Overall, all the facilities with only NO_X emission reductions predict visibility improvement from each furnace line at or below the de minimis visibility improvement threshold of 0.1 delta-dV.

Due to the sizable change in the United Taconite SO_2 emission reductions from the proposed FIP to the final FIP; the visibility improvement was re-calculated using EPA's apparent methodology from the proposed FIP. The EPA scalars (proposed FIP – Table V – C.9) were applied for each pollutant using the corrected emission reduction for NO_X and the revised emission reduction for SO_2. Then, those resultants were averaged for each of the Class I areas to obtain the "updated" EPA all pollutant estimates.

Table 6: United Taconite Visibility Impact Comparison (All Pollutants)

Class I Area	Amended EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	1.6		1.40		110%
Voyageurs	0.8		0.85		N/A
Isle Royale	1.1		0.35		320%

The comparison of the total modeling effort including both pollutant reductions is surprisingly similar (except for Isle Royale). However, when the individual pollutant impacts are examined, the problem with EPA's methodology is more clearly understood. The sulfate impacts are estimated more closely to the CAM_X results, while the nitrate impacts are grossly overestimated similar to the first three facilities.

The methodology used to isolate the sulfate and nitrate impacts separately from the current CAM$_X$ results prioritizes the sulfate and nitrate impacts as part of three separate post-processing runs (all pollutants, sulfate, and nitrate). The sulfate impact was derived by sorting the visibility impacts at each receptor from each scenario by maximum sulfate contribution for each line. Likewise, the nitrate impact was derived by sorting the visibility impacts at each receptor from each scenario by maximum nitrate contribution for each line. Then, the results were summed for both lines to obtain the overall United Taconite impact by pollutant. In nearly all circumstances, this will overestimate the impact of the NO$_X$ control. This is due to the impact from the sulfate reductions that drives the total visibility impact with a much smaller percentage from the nitrate reductions. When the nitrate impact is maximized by the sorting technique, the overall impact on the same day could be very small (e.g. nitrate = 0.1 dV; total = 0.15 dV) and would not show up as part of the overall visibility change. As detailed in the comments to the proposed FIP, it is also important to note the high probability that the maximum impacts from NO$_X$ emission reduction occur during the winter months when Isle Royale is closed to visitors and visitation at the other Class I areas is significantly reduced from summertime maximum conditions.[5]

Table 7: United Taconite Visibility Impact Comparison (Sulfate Impact)

Class I Area	Amended EPA Estimated Difference 98% dV		CAM$_X$ Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	1.0		1.29		N/A
Voyageurs	0.5		0.74		N/A
Isle Royale	0.6		0.28		210%

Table 8: United Taconite Visibility Impact Comparison (Nitrate Impact)

Class I Area	Amended EPA Estimated Difference 98% dV		CAM$_X$ Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	2.3		0.18		1300%
Voyageurs	1.1		0.08		1400%
Isle Royale	1.6		0.05		3200%

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[5] Cliffs Natural Resources (September 28, 2012), EPA-R05-OAR-0037-0045 Att. M

In the same manner as Hibbing Taconite, United Taconite's individual furnace lines were evaluated. As mentioned in the previous paragraph, the results in Table 9 for nitrate impact are biased toward higher nitrate impacts due to the sorting of the data to maximize nitrate impact.

Table 9: United Taconite Line-Specific Nitrate Visibility Impacts

Class I Area	Furnace Line		CAM_X Modeled Difference 98% dV
Boundary Waters	Line 1		0.05
	Line 2		0.1
Voyageurs	Line 1		0.02
	Line 2		0.06
Isle Royale	Line 1		0.02
	Line 2		0.03

Nonetheless, as seen for all the other furnace lines, the results for United Taconite's predicted visibility impact are at or below the deminimis threshold for visibility improvement.

Since Tilden Mining Company was not evaluated using the same methodology as the Minnesota taconite facilities, there are no specific EPA data to compare with the CAM_X results. However, it is important to understand that the results are very similar to the other results regarding the impact of NO_X emission reductions on these Class I areas.

Table 10: Tilden Mining Visibility Impact Comparison (All Pollutants)

Class I Area	EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV
Boundary Waters	N/A		0.08
Voyageurs	N/A		0.03
Isle Royale	N/A*		0.17

*EPA estimated that the proposed FIP results in 0.501 dV visibility improvement at Isle Royale from emission reduction at Tilden Mining

Table 11: Tilden Mining Pollutant-Specific Impact Comparison

Class I Area	CAM$_X$ Sulfate Modeled Difference 98% dV		CAM$_X$ Nitrate Modeled Difference 98% dV
Boundary Waters	0.07		0.01
Voyageurs	0.03		0.00
Isle Royale	0.14		0.02

The visibility impacts from NO$_X$ emission reductions at Tilden are consistent with the other modeling results and further demonstrate that significant emission reductions of NOx (3,229 tpy for Tilden) result in no visibility improvements.

III. Conclusions

Overall, the results from the three facilities with only NO$_X$ emission reductions (Hibbing Taconite, Northshore Mining, and Arcelor Mittal) and the pollutant-specific comparisons for United Taconite and Tilden Mining illustrate that nearly 15,000 tons per year of NO$_X$ reductions, even if they were technically and/or economically achievable, provide imperceptible visibility impacts at the Minnesota or nearby Michigan Class I areas. In all cases, the CAMx-predicted impacts for every furnace line are at or below the de minimis threshold for visibility improvement (0.1 delta-dV).

The fact that NO$_X$ emission reductions do not provide perceptible visibility improvement was understood by MPCA when they proposed existing control and good combustion practices as BART for taconite furnaces in northeast Minnesota. This finding has been confirmed by this detailed modeling analysis. EPA, to its credit, does not claim that its scalar "ratio" approach for predicting visibility improvement is accurate. In the final FIP, EPA provided, "Therefore, even if the ratio approach was over-estimating visibility improvement by a factor of two or three, the expected benefits would still be significant."[6] Our analysis demonstrates that the ratio approach has over-estimated impacts by a factor of ten to sixty for NO$_X$ reductions. When accurately modeled, the NO$_X$ reductions do not yield discernible visibility benefits. To that end, the following pictures from WinHaze Level 1 Visual Air Quality Imaging Modeler

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[6] Federal Register, Volume 78, Number 25, page 8720, February 6, 2013

(version 2.9.9.1) provide a visual reference for the CAM_X predicted visibility impairment from the maximum nitrate impacting facility at Isle Royale and Boundary Waters[7].

Isle Royale FIP Base – United Taconite

Isle Royale Final FIP – United Taconite

Boundary Waters FIP Base – Hibbing Taconite

Boundary Waters Final FIP – Hibbing Taconite

Given the size of the predicted visibility impacts (both less than 0.2 dV improvement), these pictures illustrate no discernible visibility improvement from NO_X reductions at either Class I area.

Ultimately, Minnesota and Michigan reached their visibility assessments in different ways, but this modeled analysis supports their conclusion that low NO_X burner technology is not BART for the furnaces modeled at Arcelor Mittal - Minorca, Hibbing Taconite, Northshore Mining Company, United Taconite, and Tilden Mining. Therefore, EPA should approve the sections of the SIPs establishing NO_X BART on this basis.

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[7] Voyageurs National Park pictures are not contained within the WinHaze program

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APPENDIX A: Visibility Impact Requirements and EPA's Scalar Approach for Estimating Visibility Impacts within the Taconite FIP

March 6, 2013

I. Summary of Visibility Impact Requirements

The relevant language related to the specific BART visibility impact modeling approach from 40 CFR 51 Appendix Y (herein, Appendix Y), *Guidelines for BART Determinations Under the Regional Haze Rule,* is provided here, in italics with some language underlined for emphasis:

5. Step 5: How should I determine visibility impacts in the BART determination?

- *For each source, run the model, at pre-control and post-control emission rates according to the accepted methodology in the protocol.*

Use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled (for the pre-control scenario). Calculate the model results for each receptor as the change in deciviews compared against natural visibility conditions. Post-control emission rates are calculated as a percentage of pre-control emission rates. For example, if the 24-hr pre-control emission rate is 100 lb/hr of SO[2], then the post control rate is 5 lb/hr if the control efficiency being evaluated is 95 percent.

- *Make the net visibility improvement determination.*

Assess the visibility improvement based on the modeled change in visibility impacts for the pre-control and post-control emission scenarios. You have flexibility to assess visibility improvements due to BART controls by one or more methods. You may consider the frequency, magnitude, and duration components of impairment. Suggestions for making the determination are:

- *Use of a comparison threshold, as is done for determining if BART-eligible sources should be subject to a BART determination. Comparison thresholds can be used in a number of ways in evaluating visibility improvement (e.g., the number of days or hours that the threshold was exceeded, a single threshold for determining whether a change in impacts is significant, or a threshold representing an x percent change in improvement).*
- *Compare the 98th percent days for the pre- and post-control runs.*

Note that each of the modeling options may be supplemented with source apportionment data or source apportionment modeling.

It should be noted that Appendix Y is a guideline for state air quality agencies to proceed with modeling of BART sources. Therefore, these are not requirements, but recommended practices for evaluation of visibility impacts. Significant discretion was given to each state regarding the use of these methods. To that end, the Minnesota Pollution Control Agency applied a different modeling system than the EPA-approved model (CALPUFF) for BART evaluations. Discussed below, the new modeling system was subsequently used by EPA as part of their FIP proposal.

Further, an excerpt from the Clean Air Act, Part C, Subpart II is provided below to establish the basis for the Appendix Y regulations related to visibility improvement.

II. Summary of EPA's approach

Specific language from the proposed and final FIPs are provided in *italics* along with comments.

EPA relied on visibility improvement modeling conducted by the Minnesota Pollution Control Agency (MPCA) and recorded in MPCA's document "Visibility Improvement Analysis of Controls Due to BART Determinations on Emission Unit's Subject to BART", October 23, 2009 [attached]. The visibility improvement modeling conducted by MPCA utilized the Comprehensive Air Quality Model with Extensions (CAMx) air quality model with the Mesoscale Meteorological Model (MM5) and the Emission Modeling System (EMS-2003). Within the CAMx modeling system, MPCA used the Particulate Source Apportionment Tool (PSAT) and included evaluation of all the elevated point emissions[1] at each facility with best available retrofit technology (BART) units. The impacts from MPCA State Implementation Plan (SIP) BART controls were determined by subtracting the impact difference between the 2002/2005 base case and 2002/2005 BART control case for each facility. EPA used the impacts from four of the six facilities modeled by MPCA (Minnesota Power – Boswell Energy Center, Minnesota Power – Taconite Harbor, Northshore Mining – Silver Bay, United Taconite). The other two facilities modeled by MPCA were utility sources (Rochester Public Utilities – Silver Lake and Xcel Energy – Sherburne Generating Plant). The locations of these sources are presented below in Figure A-1 (obtained from the MPCA 2009 document).

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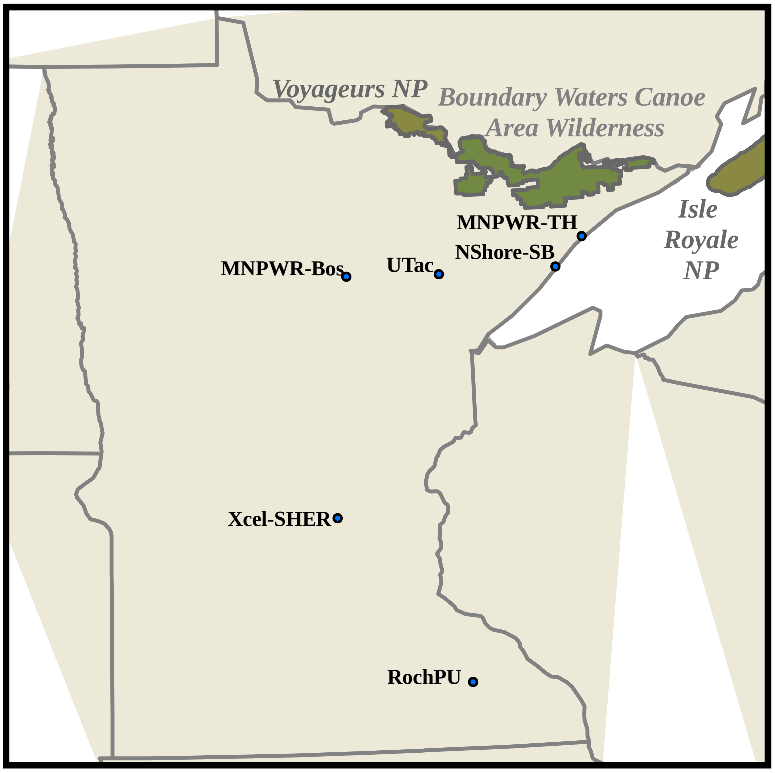
[1] Elevated point emissions include only sources with plume rise above 50m.

Figure A-1: Minnesota Facilities with BART-Determinations Assessed



In order to avoid the time and effort necessary for specific modeling of the units that EPA proposed to include in the FIP, EPA then used the average visibility impact from these four facilities to calculate two metrics for visibility improvement. The first metric is a ratio of number of days with greater than 0.5 deciview (dV) visibility divided separately by the change in SO_2 and NO_X emissions at each facility (i.e. one ratio for change in SO_2 emissions and one ratio for change in NO_X emissions). The second metric was calculated in the same fashion, but with 98th percentile visibility change divided by the change in SO_2 and NO_X emissions at each facility. These ratios were then multiplied by the estimated FIP emission reductions for the taconite facilities (including UTAC and Northshore Mining). It is important to note that there were no NO_X emission reductions modeled from any of the taconite facilities and the only source of SO_2 emission reductions from the taconite facilities was the UTAC facility.

Within the final FIP, EPA provided some additional statements that further clarified the agency's confidence regarding the use of the scalar approach for estimating visibility improvements.

III. Specific Issues Regarding EPA's Visibility Impact Estimates

Clean Air Act Section 169(A)(g)(2) – "In determining the best available retrofit technology the State (or the Administrator in determining emission limitations which reflect such technology) shall take into consideration the costs of compliance, the energy and nonair quality environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology."

Proposed FIP Page 49329 – Column 1 – "The discussion below uses MPCA's emissions data and modeled visibility impact data to derive visibility impact ratios as a function of changes in emissions of NOx and SO2 at MPCA-modeled facilities. These visibility-emission ratios were then applied to the BART-based emission changes for the source subject to this BART rule to derive possible visibility impacts."

Issues – EPA's shortcut methodology does not provide an accurate assessment of potential visibility impacts from taconite emission units subject to BART, and cannot be relied upon for several reasons stated below. The use of emission change vs. visibility impact ratios is not scientifically accurate even for a single source, much less several sources in other locations, and illustrates EPA's haste for the development of the FIP without proper modeling procedures. According to a plain language reading of the Clean Air Act section above and the best-practice recommendations within Appendix Y, the state and EPA were required to conduct a thorough evaluation of the impacts associated with the changes in emissions for each BART technology at the relevant units within each taconite facilities. EPA's methodology does not result in a thorough evaluation. If such an analysis were submitted to EPA by the state, it would be rejected as inadequate. The same should apply to EPA's analysis of the visibility improvement calculations.

MPCA used an appropriate model for estimating visibility impacts from five utility sources and one taconite source, all subject to BART, in northern Minnesota. EPA took that analyses and attempted to justify its outcomes based on its flawed methodology. Alone, the differences between the emission profiles for utility sources and taconite sources and their different locations relative to the Class I areas should preclude this type of evaluation. The difference in the emissions profile relationship between NO_X and SO_2 emissions is extremely important due to the interactive and competitive nature of the two pollutants for available ammonia (NH_3) to form ammonium nitrate or ammonium sulfate.

In addition, there are important seasonal differences in the tendency for sulfates or nitrates to be important for haze formation. Nitrates are only important in winter because significant particle formation occurs only in cold weather; oxides of nitrogen react primarily to form ozone in the summer months. On the other hand, oxidation of SO_2 to sulfate is most effective in summer with higher rates of photochemical and aqueous phase reactions. Due to the much different seasonal preferences for these two haze components, a one-size-fits-all scaling approach based upon annual averages that is insensitive to the season of the year is wholly inappropriate.

It is important to note that the only NO_X emission reductions used in the EPA scalar analyses were from utility sources. This occurred because the MPCA SIP did not include NO_X emission reductions from the United Taconite units. Therefore, the variation in emission profiles and stack parameters between utility boiler emission sources and taconite furnaces introduce another source of error with the EPA methodology.

Further, as shown in Figure A-1, the location of these sources with respect to the relevant Class I areas also causes significant problems with the EPA evaluation. The modeled visibility impacts from each source are a direct function of the wind direction. When two sources are not in the same direction with respect to the area, there is no possible way to accurately reflect the impact from the two different sources on receptor locations on any given day. For example, elevated impacts on the Voyageurs National Park from Northshore Mining would not happen on the same days as any of the other taconite sources in Minnesota.

Additionally, notwithstanding the inaccuracies of EPA's average scalar methodology, a review of the calculation of the visibility change to emission reduction ratios (i.e. MPCA-calculated visibility changes divided by SO_2 and NO_X SIP emission reductions) was conducted. This review uncovered calculation/typographical errors in the tables that were used to develop the average visibility change metrics. These simple calculation errors were subsequently corrected in the final FIP, but another inconsistency was not. The emission reductions used for NO_X within the scalar visibility calculations (Table V-C.xx) do not match the emission reduction tables in the proposed FIP (Table V – B.yy) for each facility. In one case (Northshore Mining Company), the visibility improvement reductions are greater than the baseline emissions. The attached table provides the baseline, proposed FIP, and final FIP information contained within the EPA rulemakings and docket for each taconite furnace and facility. Ultimately, even if the scalar approach used by EPA was valid, the rulemaking record is inaccurate and incomplete for the calculation of visibility impacts due to these inconsistencies.

Further, the calculation methodology for the two facilities with SO_2 and NO_X reductions (United Taconite and US Steel – Minntac) appears to utilize another invalid assumption. Also, the proposed FIP does not provide a clear explanation of the calculation of the scaled visibility impacts for these two facilities (Page 49332 – Column 1):

"To calculate the visibility impacts for the Minnesota source facilities covered by this FIP proposed rule, we multiplied the total estimated BART NOx and SO2 emission reductions for each subject facility by the appropriate visibility factor/emission change ratios in Table V-C.9 and <u>combined the results to estimate the total visibility impacts that would result from the reduction of PM2.5 concentrations</u>."

In Tables V-C.14 and V-C.16, the calculation of the visibility change with the two different pollutants is not explicitly provided within the FIP. Based on the use of the average visibility changes ("combined results") in the attached tables, one can generate "estimated visibility impacts" that are close to the values provided in the FIP tables. This pollutant averaging approach is not valid due to the previous comments regarding the interactive nature of the reaction mechanisms for ammonium nitrate and ammonium sulfate.

Proposed FIP Page 49331 – Column 1 – "The above visibility factor/emission change ratio data show significant variation from source-to-source and between impacted Class I areas. This variation is caused by differences in the relative location of the source (relative to the locations of the Class I areas), variations in background sources, variations in transport patterns on high haze factors, and other factors that we cannot assess without detailed modeling of the visibility impacts for the sources as a function of pollutant emission type."

Issue – EPA correctly establishes the significant variation in the ratio data and clearly distinguishes some (but not all) of the problems with the approach used to determine visibility impacts. Other problems include the differences in modeled utility source stack parameters vs. taconite stack parameters, the different inter-pollutant ratios at each facility, and the differences in visibility impacts due to on-going changes in emissions from 2002/2005 to current/future emission levels. Furthermore, EPA identifies the solution to solve this problem within their statement regarding "detailed modeling of the visibility impacts". This detailed modeling exercise was completed for BART-eligible Cliffs Natural Resources and Arcelor Mittal facilities in northeast Minnesota and Michigan to provide a clear record of the visibility improvements associated with the final FIP. This modeling demonstrates the lack of visibility improvement from nearly 15,000 tons per year of NO_X emission reductions and provides sufficient evidence to support the Minnesota and Michigan State Implementation Plans which called for good combustion practices as BART for NO_X at these facilities.

Proposed FIP Page 49333, Column 2 – "Each BART determination is a function of consideration of visibility improvement and other factors for the individual unit, but in general EPA's assessment of visibility impacts finds that technically feasible controls that are available at a reasonable cost for taconite plants can be expected to provide a visibility benefit that makes those controls warranted."

Issue – EPA's statement regarding visibility benefit from the FIP NO_X emission reductions are vastly overestimated based on updated CAM_X modeling for the Cliffs Natural Resources and Arcelor Mittal taconite furnaces. The modeling results evaluating the 98th percentile visibility improvements obtained from these emission reductions are generally less than 10% of the EPA estimates. Therefore, these NO_X controls are not warranted for visibility improvement in northeast Minnesota and Michigan.

Final FIP Page 8720, Column 2 – "EPA's analysis shows that based on all of the BART factors, including visibility, the selected controls are warranted. If highly reasonable and cost-effective controls had been available but visibility benefits were slight, EPA would have rejected those controls."

Issue – EPA describes exactly the situation with respect to "slight visibility benefits". Therefore, given the new information regarding the very slight modeled impact of NO_X emission reductions, EPA should reject those reductions as necessary under the BART program. Also, in the final FIP, EPA criticizes both MPCA and MDEQ for ignoring relevant information on Low NO_X Burner (LNB) technology. Now, given the length of time necessary and extensive effort required to generate this new visibility improvement data, EPA should reconsider its position on LNB as producing visibility benefits. This would allow EPA to support the original findings for these facilities within both the MPCA and MDEQ SIP with respect to NO_X emission limits.

Final FIP Page 8720, Column 3 – "EPA's proposed rule acknowledged the uncertainty associated with the visibility impact ratio approach, but noted that despite the uncertainties, the Agency was confident that the information was adequate to assess potential visibility improvements due to emission reductions at the specific facilities."

"Given the geographic proximity of the taconite facilities to those that were modeled, EPA believes that the ratio approach provide adequate assurance of the visibility improvements that can be expected from the proposed emission reductions."

"In the proposed rule's summary of the impacts at Boundary Waters, Voyageurs, and Isle Royale, these values ranged from 1.3 to 7.1 dVs of improvement with between 17 and 93 fewer days above the 0.5 dV threshold. Therefore, even if the ratio approach was over-estimating visibility improvements by a factor of two or three, the expected benefits would still be significant."

Final FIP Page 8721, Column 3 – "EPA stands by the results of its ratio approach and believes that it produced reasonable results for the sources examined."

Issue – EPA again chose to ignore the specific technical issues discussed above regarding the use of the ratio approach and has incorrectly assumed that this approach will provide an accurate assessment of the visibility benefits from the Cliffs and Arcelor taconite facilities. Based on the refined CAM_X modeling results using a conservative estimate of EPA's final FIP emission reduction scenario, it is obvious that the ratio approach does not provide any assurance of the visibility improvements. Further, the estimates for visibility improvement are over-estimated by between a factor of ten and sixty. Therefore, the impacts are not "significant" as referenced in EPA's response to comment within the final FIP rulemaking. The lack of technical validity contained within the EPA scalar approach is alarming. Even more alarming is the agency's refusal to conduct the type of detailed analyses necessary to allow for a technically valid answer on a rulemaking that will cost the taconite industry millions of dollars.

IV. Summary

The CAM_X modeling approach undertaken by Cliffs and Arcelor provides the best approximation of the visibility improvements from the emission reductions within the final FIP. This method replaces the use of the average ratio approach used by EPA with refined, photochemical modeling for the Cliffs and Arcelor facilities. The results of the analysis confirm the findings of the MPCA in its 2009 SIP that NO_X emission reductions do not have sufficient impact to warrant further consideration. At this point, we affirm that EPA's simple assessment is not credible, and any visibility improvement conclusions for NO_X are not technically sound. The visibility improvement results estimated by EPA using the ratio approach are between ten and sixty times greater than the results generated using the CAM_X modeling system. In essence, the modeling conducted here provides EPA another opportunity to support the findings of the MPCA and MDEQ SIPs with respect to NO_X emissions impacts at the Cliffs and Arcelor facilities.

Cliffs Natural Resources and Arcelor Mittal Taconite FIP Emission Summary

				Emissions			Emission Reductions			Emissions	
				Proposed FIP			Baseline - Prop FIP	Baseline - Prop FIP		Final FIP	
Facility	Emission Unit		Pollutant	Baseline	FIP		Emission Tables	Visibility Calcs			
	ModID	Description		tons/yr	tons/yr	Note(s)	tons/yr	tons/yr	Note(s)	lb/hr	Note(s)
Hibbing Taconite Company	{3}	Line 1	NOx	2,497	749	[1]	1,748				[4]
			SO2	202	202	[2]	0			82.6	[5]
	{4}	Line 2	NOx	2,144	643	[1]	1,500				[4]
			SO2	180	180	[2]	0			82.6	[5]
	{5}	Line 3	NOx	2,247	674	[1]	1,573				[4]
			SO2	188	188	[2]	0			82.6	[5]
	HTC	BART Units Combined	NOx	6,888	2,066		**4,821**	**5,259**	[3]		
			SO2	570	570		0	0	[3]	247.8	
Northshore Mining Company		Process Boiler 1/2	NOx	41	21	[6]	21				[10]
			SO2								
	{24}	Furnace 11	NOx	386	116	[7]	270				[11]
			SO2	38	38	[8]	0			19.5	[12]
	{25}	Furnace 12	NOx	378	113	[7]	264				[11]
			SO2	35	35	[8]	0			19.5	[12]
	NSM	BART Units Combined	NOx	805	250		**555**	**926**	[9]		
			SO2	73	73		0	0	[9]	39	
Tilden Mining Company	{1}	Boiler #1/2	NOx	79	79	[13]	0				
			SO2	0	0	[14]	0				[19]
	{3}	Ore Dryer # 1	NOx	15	15	[15]	0				
			SO2	34	34	[15]	0				[20]
	{5}	Furnace #1	NOx	4,613	1,384	[16]	3,229				[21]
			SO2	1,153	115	[17]	1,038			55	[22][23]
	TMC	BART Units Combined	NOx	4,707	1,478		3,229	3,229	[18]		
			SO2	1,187	150		1,038	1,038	[18]		
United Taconite	{26}	Line 1	NOx	**1,643**	493	[24]	1,150				[27]
			SO2	1,293	129	[25]	1,164			155	[28]
	{24}	Line 2	NOx	**3,687**	1,106	[24]	2,581				[27]
			SO2	2,750	275	[25]	2,475			374	[28]
	UTAC	BART Units Combined	NOx	5,330	1,599		**3,731**	**3,208**	[26]		
			SO2	4,043	404		3,639	3,639	[26]	529	[28]
Arcelor Mittal	ARC {12}	Line 1	NOx	3,639	1,092	[29]	**2,547**	**2,859**	[31]		[32]
			SO2	179	179	[30]	0	0	[31]	38.2	[33]

TOTAL BART UNIT	NOx	21,369	6,485		14,884	15,481
	SO2	6,053	1,376		4,677	4,677

🟨 Facility BART Unit Summary or Overall Summary
🟩 FIP Baseline does not match reference
🟧 FIP Table B emission tables do not match Table C visibility calculation tables

EPA Furnace
NOx Control %
70%

Notes:

[1] HTC Line 1-3 - USEPA FIP NOx Baseline Emissions Proposed FIP Table V - B.24 ; Proposed FIP NOx Emissions = 70% Control from Baseline
Typographical Error in Table V - B.24 for Line 1 Baseline Emissions (2,143.5 TPY Proposed FIP; should have been 2,497 TPY)
[2] HTC Line 1-3 - USEPA FIP SO2 Baseline Emissions from Proposed FIP Table V - B.27
[3] HTC - USEPA Proposed BART FIP Table V - C.11
[4] HTC Furnace Lines - USEPA Final BART limit of 1.5 lb NOx/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only).
[5] HTC Furnace Lines - USEPA final BART combined limit of 247.8 lb SO2/hr [82.6 lb/hr each for Lines 1 to 3] (30-day rolling avg); can be adjusted based on CEMs data.
[6] NSM Process Boilers 1&2 - NOx Emissions from Proposed FIP Table V - B.12 (p49318); LNB 50% Control from Baseline of 41.2 tons/year
[7] NSM Furnace 11/12 - NOx Emissions (Baseline and Proposed FIP Control) from Proposed FIP - Table V - B.8; FIP Emisssions = 70% Control from Baseline
[8] NSM Furnace 11/12 - No Additional SO2 Control Applied by Proposed FIP; Baseline FIP Emission Rate from Table V - B.10
[9] NSM - USEPA Proposed BART FIP Table V - C.12
[10] NSM Process Boilers 1&2 - USEPA Final BART limit of 0.085 lb NOx/MMBTU (30-day rolling average) [No additional control].
[11] NSM Furnace 11/12 - USEPA Final BART limit of 1.5 lb NOx/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only).
[12] NSM Furnace 11/12 - USEPA final BART combined limit of 39.0 lb SO2/hr (30-day rolling average); must be adjusted based on CEMs data.
[13] Tilden Process Boilers 1 & 2 - NOx Baseline Emissions Proposed FIP Table V - B.38
[14] Tilden Process Boilers 1 & 2 - SO2 Baseline Emissions Proposed FIP Table V - B.37 (0.25 TPY)
[15] Tilden Dryer #1 Emissions from Proposed FIP Table V - B.39 (SO2) and Table V - B.40 (NOx) - 34.07 TPY SO2, 15.1 TPY NOx
[16] Tilden Furnace 1 - NO2 Baseline and Proposed FIP Control Emissions - Proposed FIP Table V - B.34 (FIP Emissions = 70% Control from Baseline)
[17] Tilden Furnace 1 - Proposed FIP SO2 Emissions - Table V-B.36; Spray Dry Absorption 90%; Proposed FIP Text says 95% Control or 5 ppm;
Baseline Emissions Back-calculated from 90% control
[18] Tilden Furnace 1 - USEPA did not calculate visibility improvement for Tilden (Used emission difference Baseline - Proposed FIP)
[19] Tilden - USEPA Final BART limit of 1.2%S in fuel combusted by Process Boiler #1 and #2
[20] Tilden - USEPA Final BART limit of 1.5%S in fuel combusted by Ore Dryer #1
[21] Tilden Furnace 1- USEPA Final BART limit of 1.5 lb NOx/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only);
NOx emissions referenced in final FIP text as 65% control from baseline (page 8721)
[22] Tilden Furnace 1 - USEPA Final BART restriction - Only combust natural gas in Grate Kiln Line 1 with limit computed in lb SO2/hr based on CEMs;
SO2 emissions referenced in final FIP text at 80% control from baseline (page 8721)
[23] Tilden Furnace 1 - USEPA Final BART Modeling File (Part of Final Rulemaking Docket) Conducted by NPS - 55 lb/hr SO2
[24] UTAC Line 1-2 - USEPA NOx Baseline Emissions Proposed FIP Table V - B.14 ; Proposed FIP NOx Emissions = 70% Control from Baseline
[25] UTAC Line 1-2 - USEPA proposed FIP Baseline SO2 Emissions Table V - B.17; 90% Control in Table, but 95% Control within text - Proposed FIP (page 49319)
[26] UTAC - USEPA Proposed BART FIP Table V - C.13
[27] UTAC Line 1-2 - USEPA Final BART NOx Limit of 1.5 lb/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only)
[28] UTAC Line 1-2 - USEPA Final BART SO2 Limit of 529 lb/hr Combined (155 lb/hr - Line 1 & 374 lb/hr - Line 2).
[29] Arcelor - USEPA proposed FIP Baseline NOx Emissions Table V - B.19; Proposed FIP NOx Emissions = 70% Control from Baseline
[30] Arcelor - USEPA proposed FIP Baseline SO2 Emissions Table V - B.21
[31] Arcelor - USEPA Proposed BART FIP Table V - C.10
[32] Arcelor - USEPA Final BART SO2 Limit of 38.16 lb/hr for Arcelor.
[33] Arcelor - USEPA Final BART NOx Limit of 1.5 lb/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only)

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APPENDIX B: Barr and MPCA CAM_X Modeling Comparison of Results

March 6, 2013

Minnesota Power – Taconite Harbor (BART01)

MPCA
Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	94	90	-4	11	9	-2	30	27	-3
98th Percentile Δ dv	**2002**	9.2	8.3	-0.9	0.8	0.7	-0.1	2.2	1.9	-0.3

Barr
Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	95	90	-5	11	9	-2	30	27	-3
98th Percentile Δ dv	**2002**	9.14	8.25	-0.89	0.82	0.68	-0.14	2.22	1.88	-0.34

Minnesota Power – Boswell (BART04)

MPCA
Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**DifferEnce**	**Base**	**BART**	**Difference**	**Base**	**BART**	**DifferEnce**
Days > 0.5 dv	**2002**	111	60	-51	86	58	-28	48	27	-21
98th Percentile Δ dv	**2002**	4.3	2.4	-1.9	4.4	2.7	-1.8	2.0	1.0	-1.0

Barr
Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**DifferEnce**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	110	61	-49	86	58	-28	47	27	-20
98th Percentile Δ dv	**2002**	4.27	2.37	-1.90	4.43	2.65	-1.78	1.96	0.98	-0.98

Northshore Mining – Silver Bay (BART05)

MPCA

Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	77	72	-5	9	8	-1	20	15	-5
98th Percentile Δ dv	**2002**	3.96	3.79	-0.17	0.6	0.5	-0.1	0.9	0.7	-0.2

Barr

Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	78	72	-6	9	8	-1	20	15	-5
98th Percentile Δ dv	**2002**	3.96	3.78	-0.18	0.63	0.50	-0.13	0.90	0.73	-0.17

United Taconite (BART26)

MPCA

Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	59	44	-15	32	20	-12	8	1	-7
98th Percentile Δ dv	**2002**	3.0	1.7	-1.3	1.8	0.8	-0.9	0.6	0.3	-0.3

Barr

Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	63	46	-17	34	20	-14	8	1	-7
98th Percentile Δ dv	**2002**	3.02	1.69	-1.33	1.78	0.85	-0.93	0.59	0.28	-0.31

Xcel Sherburne (BART13)

MPCA
Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	74	58	-16	53	39	-14	42	30	-12
98th Percentile Δ dv	**2002**	2.5	1.9	-0.6	2.2	1.7	-0.5	1.4	1.0	-0.4

Barr
Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	74	59	-15	53	39	-14	42	29	-13
98th Percentile Δ dv	**2002**	2.48	1.90	-0.58	2.18	1.65	-0.53	1.44	1.06	-0.38

Rochester Public Utilities (BART07)

MPCA
Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	0	0	0	0	0	0	0	0	0
98th Percentile Δ dv	**2002**	0.1	0.1	0.0	0.1	0.0	0.0	0.1	0.0	0.0

Barr
Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	0	0	0	0	0	0	0	0	0
98th Percentile Δ dv	**2002**	0.10	0.06	0.04	0.08	0.04	0.04	0.09	0.04	0.05

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APPENDIX C: CAM$_X$ PSAT Source List

March 6, 2013

2009 MPCA Tracked, Elevated Point Sources

RANKTRAC BARTSRC_ID	RECEPTOR BARTSRC_ID	Facility ID	Facility Name [1]
1	2	2703100001	Minnesota Power - Taconite Harbor
2	3	2703700003	XCEL - Black Dog
3	4	2705300015	XCEL - Riverside
4	5	2706100004	Minnesota Power - Boswell
5	6	2707500003	Northshore Mining Co - Silver Bay
6	7	2709900001	Austin Utilities - NE Power Station
7	8	2710900011	Rochester Public Utilities
8	9	2711100002	Otter Tail Power - Hoot Lake
9	10	2712300012	XCEL - High Bridge
10	11	2713700013	Minnesota Power - Laskin
11	12	2713700027	Hibbing Public Utilities
12	13	2713700028	Virginia Dept of Public Utilities
13	14	2714100004	XCEL - Sherburne Generating Plant
14	15	2716300005	XCEL - Allen S. King
15	16	2701700002	Sappi - Cloquet
16	17	2703700011	Flint Hill Resources - Pine Bend
17	18	2706100001	Blandin Paper / Rapids Energy
18	19	2707100002	Boise Cascade - International Falls
19	20	2713700005	US Steel - Minntac
20	21	2713700015	Minnesota Power - ML Hibbard
21	22	2713700022	Duluth Steam Cooperative
22	23	2713700031	Georgia Pacific - Duluth
23	24	2713700061	Hibbing Taconite
24	25	2713700062	Arcelor Mittal
25	26	2713700063	US Steel - Keetac
26	27	2713700113	United Taconite - Fairlane Plant [2]
27	28	2700900011	International Paper - Sartell
28	29	2716300003	Marathon Ashland Petroleum
29	30	2713700083	Potlatch - Cook
30	31	2706100010	Potlatch - Grand Rapids

🟨	Included in MPCA BART SIP Modeling Report
[1]	MPCA tracked all point sources on a facility-basis
[2]	MPCA Emissions did not Include UTAC Line 1

2012/2013 Barr Tracked, Elevated Point Sources

Output ID	BARTSRC_ID	Facility ID	Facility / Unit Name [3]
MNPWTH	2	2703100001	Minnesota Power - Taconite Harbor
XCELBD	3	2703700003	XCEL - Black Dog
XCELRV	4	2705300015	XCEL - Riverside
MNPWBO	5	2706100004	Minnesota Power - Boswell
NSMSBU	6	2707500003	Northshore Mining Co - Silver Bay (All Other)
AUSTIN	7	2709900001	Austin Utilities - NE Power Station
ROCHPU	8	2710900011	Rochester Public Utilities
OTTRHL	9	2711100002	Otter Tail Power - Hoot Lake
XCELHB	10	2712300012	XCEL - High Bridge
MNPWLS	11	2713700013	Minnesota Power - Laskin
HIBBPU	12	2713700027	Hibbing Public Utilities
VIRGPU	13	2713700028	Virginia Dept of Public Utilities
XCELSB	14	2714100004	XCEL - Sherburne Generating Plant
XCELAK	15	2716300005	XCEL - Allen S. King
SAPPIC	16	2701700002	Sappi - Cloquet
FHRPNB	17	2703700011	Flint Hill Resources - Pine Bend
BLNPAP	18	2706100001	Blandin Paper / Rapids Energy
BOISEC	19	2707100002	Boise Cascade - International Falls
MINNTC	20	2713700005	US Steel - Minntac
MNPWHB	21	2713700015	Minnesota Power - ML Hibbard
DULSTM	22	2713700022	Duluth Steam Cooperative
GEOPAC	23	2713700031	Georgia Pacific - Duluth
HIBTAC	24	2713700061	Hibbing Taconite (All Other)
ARCELR	25	2713700062	Arcelor Mittal (All Other)
KEETAC	26	2713700063	US Steel - Keetac
UTACFP	27	2713700113	United Taconite - Fairlane Plant (All Other)
INTPAP	28	2700900011	International Paper - Sartell
MARTHN	29	2716300003	Marathon Ashland Petroleum
POTLTC	30	2713700083	Potlatch - Cook
POTLTG	31	2706100010	Potlatch - Grand Rapids
TILDEN	32	26103B4885	Tilden Mining Company (All Other)
NSMPB1	33	2707500003	Northshore Mining - Power Boiler 1
NSMPB2	34	2707500003	Northshore Mining - Power Boiler 2
NSMF11	35	2707500003	Northshore Mining - Furnace 11
NSMF12	36	2707500003	Northshore Mining - Furnace 12
UTACL1	37	2713700113	United Taconite - Line 1
UTACL2	38	2713700113	United Taconite - Line 2
ARCLN1	39	2713700062	Arcelor Mittal - Line 1
HBTCF1	40	2713700061	Hibbing Taconite - Line 1
HBTCF2	41	2713700061	Hibbing Taconite - Line 2
HBTCF3	42	2713700061	Hibbing Taconite - Line 3
TILDL1	43	26103B4885	Tilden Mining - Line 1

🟩 Included in Barr Output Evaluation

[3] Barr tracked furnace stacks and other noted stacks on a unit-basis
while all other stacks were included in the "All Other" stacks

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APPENDIX D: Summary of CAM_X Elevated Point Source Emissions

March 6, 2013

Summary of CAMx Elevated Point Source Emissions

				Emissions		Emissions		Emission Reductions
				Proposed FIP		Final FIP		Baseline - Final FIP
	Emission Unit		Pollutant	Baseline		FIP		
Facility	ModID	Description		tons/yr	Note(s)	tons/yr	Note(s)	tons/yr
Hibbing Taconite Company	{3}	Line 1	NOx	2,497	[1]	749	[3]	1,748
			SO2	202	[2]	202	[4]	0
	{4}	Line 2	NOx	2,144	[1]	643	[3]	1,500
			SO2	180	[2]	180	[4]	0
	{5}	Line 3	NOx	2,247	[1]	674	[3]	1,573
			SO2	188	[2]	188	[4]	0
	HTC	BART Furnaces Combined	NOx	6,888		2,066		4,821
			SO2	570		570		0
Northshore Mining Company		Process Boiler 1/2	NOx	41	[5]	41	[8]	0
			SO2					
	{24}	Furnace 11	NOx	386	[6]	116	[9]	270
			SO2	38	[7]	38	[10]	0
	{25}	Furnace 12	NOx	378	[6]	113	[9]	264
			SO2	35	[7]	35	[10]	0
	NSM	BART Furnaces Combined	NOx	764		229		535
			SO2	73		73		0
Tilden Mining Company	{1}	Boiler #1/2	NOx	79	[11]	79	[16]	0
			SO2	0	[12]	0	[17]	0
	{3}	Ore Dryer # 1	NOx	15	[13]	15	[18]	0
			SO2	34	[13]	34	[19]	0
	{5}	Furnace #1	NOx	4,613	[14]	1,384	[20]	3,229
			SO2	1,153	[15]	231	[21]	922
	TMC	BART Furnace	NOx	4,613		1,384		3,229
			SO2	1,153		231		922
United Taconite	{26}	Line 1	NOx	**1,643**	[22][23]	493	[26]	1,150
			SO2	1,293	[25]	577	[27]	716
	{24}	Line 2	NOx	**3,687**	[22][24]	1,106	[26]	2,581
			SO2	2,750	[25]	1,392	[27]	1,357
	UTAC	BART Furnaces Combined	NOx	5,330		1,599		3,731
			SO2	4,043		1,969		2,074
Arcelor Mittal	ARC {12}	Line 1	NOx	3,639	[28]	1,092	[30]	2,547
			SO2	179	[29]	179	[31]	0

TOTAL BART Furnaces	NOx	21,233		6,370		14,863
	SO2	6,018		3,022		2,996

🟨 Facility Furnace Unit Summary or Overall Summary
🟩 FIP Baseline does not match reference

Notes:

[1] HTC Line 1-3 - USEPA FIP NOx Baseline Emissions Proposed FIP Table V - B.24
[2] HTC Line 1-3 - USEPA FIP SO2 Baseline Emissions from Proposed FIP Table V - B.27
[3] HTC Line 1-3 - USEPA Proposed FIP NOx = 70% control from Baseline - Table V - B.24; Final FIP (1.2 or 1.5 lb/MMBTU) assumed equivalent
[4] HTC Line 1-3 - USEPA Final FIP - no additional SO2 control (Final FIP = Baseline Emissions)
[5] NSM Process Boilers 1&2 - NOx Emissions from Proposed FIP Table V - B.12 (p49318)
[6] NSM Furnace 11/12 NOx Emissions from Proposed FIP - Table V - B.8
[7] NSM Furnace 11/12 SO2 Baseline FIP Emission Rate from Proposed FIP Table V - B.10
[8] NSM Process Boilers #1 and #2 - USEPA Final BART limit of 0.085 lb NOx/MMBTU (30-day rolling average) - No additional control.
[9] NSM Furnace 11/12 - USEPA Proposed FIP NOx = 70% control from Baseline _ Table V - B.8; Final FIP (1.2 or 1.5 lb/MMBTU) assumed equivalent
[10] NSM Furnace 11/12 - no Additional SO2 Control Applied by Proposed or Final FIP (Final FIP = Baseline Emissions)
[11] Tilden Process Boilers 1 & 2 NOx Baseline Emissions Proposed FIP Table V - B.38
[12] Tilden Process Boilers 1 & 2 SO2 Baseline Emissions Proposed FIP Table V - B.37 (0.25 TPY)
[13] Tilden Dryer #1 Emissions from Proposed FIP Table V - B.39 (SO2) and Table V - B.40 (NOx) - 34.07 TPY SO2, 15.1 TPY NOx
[14] Tilden Furnace 1 NO2 Baseline - Proposed FIP Table V - B.34
[15] Tilden Furnace 1 SO2 Baseline - Proposed FIP Projected SO2 Emission Reductions - Table V-B.36; Baseline Emissions Back-calculated from 90% control
[16] Tilden Process Boilers 1 & 2 - No additional NOx control (Final FIP = Baseline Emissions)
[17] Tilden Process Boilers 1 & 2 - USEPA Final BART limit of 1.2%S in fuel - No additional SO2 control (Final FIP = Baseline Emissions)
[18] Tilden Ore Dryer #1 - No additional NOx control (Final FIP = Baseline Emissions)
[19] Tilden Ore Dryer #1 - USEPA Final BART limit of 1.5%S in fuel - No additional SO2 control (Final FIP = Baseline Emissions)
[20] Tilden Furnace 1 - USEPA Proposed FIP NOx = 70% control from Baseline _ Table V - B.34; Final FIP (1.2 or 1.5 lb/MMBTU)
NOx emissions referenced in final FIP text at 65% control from baseline (page 8721); but that is not consistent with the remaining facilities
Modeled emissions assumed 70% control to provide maximum emission reductions
[21] Tilden - USEPA Final BART restriction - Only combust natural gas in Grate Kiln Line 1 with limit computed in lb SO2/hr based on CEMs;
SO2 emissions referenced in final FIP text at 80% control from baseline (page 8721)
[22] UTAC - USEPA FIP NOx Baseline Emissions Proposed FIP Table V - B.14
[23] UTAC - Line 1 NOx Permit limit specified in permit 13700113-005 - 1,655 TPY, issued 8/19/2010, page A-49 (reference from USEPA 114 Request Question 6)
[24] UTAC - Line 2 NOx Permit limit specified in permit 13700113-005 - 3,692 TPY, issued 8/19/2010, page A-56 (reference from USEPA 114 Request Question 6)
[25] UTAC Line 1&2 - USEPA proposed FIP Baseline SO2 Emissions Table V - B.17; 90% Control in Table, 95% Control within text _ Proposed FIP (page 49319)
Modeled baseline emissions back-calculated from 90% Control; SO2 Reductions match Table V - C.13 in Proposed FIP
[26] UTAC Line 1&2 - USEAP Proposed FIP NOx = 70% Control from Baseline Table V - B.14; Final FIP (1.2 or 1.5 lb/MMBTU)
Modeled emissions assumed 70% control to provide maximum emission reductions
[27] UTAC Line 1&2 - USEPA Final BART SO2 Limit of 529 lb/hr Combined (155 lb/hr - Line 1 & 374 lb/hr - Line 2) - 30-day rolling average.
Modeled Final FIP emissions used the limits and 85% operating factor to calculate the annual emissions (designed to maximize reductions)
[28] Arcelor Line 1 - USEPA proposed FIP Baseline NOx Emissions Table V - B.19
[29] Arcelor Line 1 - USEPA proposed FIP Baseline SO2 Emissions Table V - B.21
[30] Arcelor Line 1 - Proposed FIP NOx = 70% Control from Baseline Table V - B.19; Final FIP (1.2 or 1.5 lb/MMBTU) assumed equivalent
[31] Arcelor Line 1 - USEPA Final FIP - no additional SO2 control (Final FIP = Baseline Emissions)

APPENDIX E: Electronic Mail Requests - Proposed and Final FIP Emission Clarifications

March 6, 2013

From: Jeffry D. Bennett
Sent: Thursday, January 31, 2013 7:42 PM
To: 'Rosenthal.steven@Epa.gov'
Cc: 'Long, Michael E'
Subject: Clarification Regarding Emissions within the Final Taconite BART FIP
Attachments: EPA_FIP_Emission_Summary_01292013.xls

Steve,

Pursuant to our conversation last week regarding the baseline and controlled emission inventories within the proposed and final BART FIP for taconite furnaces, this e-mail is designed to request clarification regarding certain information contained in the rule. To that end, attached you will find a spreadsheet that summarizes and documents (to the maximum extent possible) the emission inventory data within the FIP rulemakings.

Specifically at this time, we are requesting:

(1) verification of the UTAC baseline NOx information for Line 1 and Line 2 (‘Summary’ Tab, Cells E30 and E32),

(2) clarification of the differences between the information contained in Columns H and I of the spreadsheet, Column H contains the difference between the FIP baseline and proposed FIP control emissions and was calculated from information within Table V-B.xx* - NOx or SO2 facility specific emission data. The Column I information contains the emission reductions obtained from Table V-C.yy visibility improvement estimate tables. For each facility, these two columns should match, but the NOx information does not. Ultimately, the bases for Table V-C.yy data is the component that is missing.

*Note: for Hibbing Taconite Line 1, a typographical error was discovered in Table V-B.24 and corrected in the spreadsheet.

(3) EPA’s estimates of final FIP emissions on a tons/year basis with the corresponding emission reductions (i.e. FIP baseline – final FIP control) expected by EPA. This information would replace the “?” in Columns L and M of the spreadsheet. Along with the estimates, documentation of their bases would be extremely beneficial. For example, NOx could include either a % reduction from baseline or MMBTU/hour, Hours/year, and the appropriate lb NOx/MMBTU limit.

If you have any questions regarding these requests, feel free to contact Mike Long or myself. Thank you for your time.

Jeffry D. Bennett, PE
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JBennett@barr.com
www.barr.com

From: Jeffry D. Bennett
Sent: Thursday, February 14, 2013 12:02 PM
To: 'Robinson.randall@Epa.gov'
Subject: FW: Clarification Regarding Emissions within the Final Taconite BART FIP
Attachments: EPA_FIP_Emission_Summary_01292013.xls

Randy,

I talked with Steve Rosenthal yesterday about the taconite BART FIP emissions (see e-mail below). He told me that you “wrote the section on visibility improvement” and suggested I contact you about item 2 and a portion of the information requested in item 3. Barr Engineering is contracted with Cliffs Natural Resources and Arcelor Mittal to provide their taconite facilities with technical support regarding the FIP. At this point, we are trying to summarize and document the bases for the SO2 and NOx emissions that were used in the EPA baseline, the proposed FIP, and the final FIP for all their facilities.

The attached spreadsheet that I sent Steve previously includes the summary. Item 2 is related to differences between the NOx emission reductions used in the ratio visibility improvement calculations in the proposed FIP (Table V – C.yy) and the emission reductions in Table V – B.xx for each facility. Steve thought you would have the information about the basis for the Table V – C.yy reductions.

Item 3 is requesting information about the final FIP emission reductions. Specifically, you would probably have information regarding the emissions for Tilden Mining and United Taconite (UTAC) from the CALPUFF modeling completed by Trent Wickman referenced in the final FIP rulemaking docket. Please give me a call to discuss this at your earliest convenience. We are attempting to finalize the summary by COB tomorrow. Thanks for any help you can provide.

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APPENDIX F: CAMx Modeling Results by Facility

March 6, 2013

Arcelor Mittal CAMx Emissions and Modeling Results

Arcelor Emissions

Unit	EPA FIP Baseline NOx Emission (TPY) [1]	Final FIP NOx Emission (TPY) [1]	NOx Emission Difference (TPY)	EPA FIP Baseline SO2 Emission (TPY) [2]	Final FIP SO2 Emission (TPY)[3]	SO2 Emission Difference (TPY)
Line 1	3,639	1,092	2,547	179	179	0
TOTAL	**3,639**	**1,092**	**2,547**	**179**	**179**	**0**

[1] FIP Baseline and Control NOx Emissions from EPA Proposed FIP Table V-B.19 – Projected Annual NOx Emission Reductions [TPY].

[2] FIP Baseline SO2 Emissions are from EPA Proposed FIP Table V-B.21 – Annual SO2 Emissions [TPY]

[3] No SO2 emission reductions in Final FIP (i.e. EPA Baseline = Final FIP control)

Arcelor CAMx Results (By Unit) [4]

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Proposed FIP Days > 0.5 dV	Proposed FIP 98% dV	Difference Days >0.5 dV [5]	Difference 98% dV [5]
Boundary Waters						
2002						
Line #1	30	0.789	18	0.713	12	0.076
Facility Total	43	0.99	35	0.96	8	0.03
2005						
Line #1	7	0.491	3	0.326	4	0.165
Facility Total	19	0.74	8	0.55	11	0.19
Voyageurs						
2002						
Line #1	1	0.287	0	0.202	1	0.085
Facility Total	1	0.34	0	0.22	1	0.12
2005						
Line #1	0	0.182	0	0.122	0	0.060
Facility Total	0	0.22	0	0.16	0	0.06
Isle Royale						
2002						
Line #1	0	0.075	0	0.053	0	0.022
Facility Total	0	0.09	0	0.06	0	0.03
2005						
Line #1	0	0.049	0	0.033	0	0.016
Facility Total	0	0.06	0	0.04	0	0.02

[4] Visibility benchmarks:

0.5 dV impact is the BART eligibility threshold (i.e. if a facility has less than 0.5 dV impact in the baseline, no BART is required),

1.0 dV difference is the presumed human perceptible level for visibility improvement, and

0.1 dV difference was defined by other agencies as the degree of visibility improvement that is too low to justify additional emission controls. Also, EPA's Regional Haze Rule mentions that "no degradation" to visibility would be "defined as less than a 0.1 deciview increase."

[5] These two columns provide the difference in predicted days >0.5 dV and 98th percentile visibility improvement from the baseline to the FIP control emissions. The annual average number of days with > 0.5 dV improvement at all the Class I areas is considerably less than EPA's estimate (11 to 53). Also, the averages of the 98th percentile differences are **10 to 37 times less** than the predicted improvement by EPA. Note: the table below formed the basis for EPA's inclusion of control necessary at Arcelor Mittal.

Arcelor Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

(EPA Table C Emission Difference = 2,859 TPY NOx)[6]

(EPA Table B Emission Difference = 2,547 TPY NOx)[7]

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV[8]	CAMx Modeled Difference 98% dV
Boundary Waters	24	1.7		10	0.11
Voyageurs	11	0.9		1	0.09
Isle Royale	18	1.1		0	0.03

[6] Emission Difference Obtained from EPA Proposed FIP Table V-C.10 – Estimated Emission Reductions and Resulting Changes in Visibility Factors for Arcelor Mittal.

[7] Emission Difference Obtained from EPA Proposed FIP Table V-B.19.

[8] The number of days with visibility >0.5 deciviews (dV) can be a misleading indicator as illustrated by the Arcelor Mittal and Northshore Mining results (below). The 98th percentile visibility improvement at Boundary Waters during the 2002 modeled year was 0.03 dV. However, the modeling predicts this insignificant change will result in eight more days of "good visibility", defined as days with visibility at or below the 0.5 deciview threshold. Further, the Northshore Mining results at Isle Royale indicate a miniscule 0.01 deciviews, or one hundred times less than a perceptible improvement to visibility. Nonetheless, the modeling predicts this insignificant change will result in two more days of "good visibility". In both circumstances, this does not mean that the visibility change was discernible. The model gives credit for an improved day when the predicted impairment falls from 0.51 to 0.50 deciviews, but that improvement is illusory because at 0.51 deciviews people do not perceive a regional haze problem. The difference in visibility from natural background when evaluating the baseline could have several days near the 0.5 dV "contribute to visibility degradation" threshold, but well less than the 1 dV "cause visibility degradation" threshold. Then, a very small change in visibility from the baseline to the controlled emission scenario (~0.01 – 0.1 dV) could cause a large number of days to be less than the 0.5 dV benchmark without producing any real benefit to visibility.

Hibbing Taconite (HibTac) CAMx Emissions and Modeling Results

HibTac Emissions

Unit	EPA FIP Baseline NOx Emission (TPY)	Final FIP NOx Emission (TPY)	NOx Emission Difference (TPY)	EPA FIP Baseline SO2 Emission (TPY)	Final FIP SO2 Emission (TPY)	SO2 Emission Difference (TPY)
Line 1	2,497	749	1,748	202	202	0
Line 2	2,144	643	1,500	180	180	0
Line 3	2,247	674	1,573	188	188	0
TOTAL	**6,888**	**2,066**	**4,822**	**570**	**570**	**0**

HibTac CAMx Results (By Unit)

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
2002						
Line 1	1	0.337	1	0.305	0	0.032
Line 2	2	0.287	0	0.260	2	0.027
Line 3	1	0.318	0	0.245	2	0.073
Facility Total	33	1.10	22	0.96	11	0.14
2005						
Line 1	0	0.217	0	0.158	0	0.057
Line 2	0	0.203	0	0.124	0	0.079
Line 3	0	0.223	0	0.140	0	0.083
Facility Total	14	0.85	11	0.62	3	0.23
Voyageurs						
2002						
Line 1	0	0.197	0	0.168	0	0.029
Line 2	0	0.197	0	0.159	0	0.038
Line 3	0	0.211	0	0.163	0	0.048
Facility Total	18	0.67	10	0.61	8	0.06
2005						
Line 1	0	0.126	0	0.102	0	0.024
Line 2	0	0.122	0	0.085	0	0.037
Line 3	0	0.133	0	0.103	0	0.030
Facility Total	8	0.51	5	0.36	3	0.15

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Isle Royale						
2002						
Line 1	0	0.053	0	0.047	0	0.006
Line 2	0	0.045	0	0.036	0	0.009
Line 3	0	0.046	0	0.037	0	0.009
Facility Total	0	0.16	0	0.13	0	0.03
2005						
Line 1	0	0.038	0	0.027	0	0.011
Line 2	0	0.034	0	0.022	0	0.012
Line 3	0	0.037	0	0.026	0	0.011
Facility Total	0	0.13	0	0.09	0	0.04

HibTac Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

(EPA Table C Emission Difference = 5,259 TPY NOx)[8]
(EPA Table B Emission Difference = 4,822 TPY NOx)[9]

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 98% dV
Boundary Waters	44	3.2		7	0.19
Voyageurs	21	1.7		5	0.11
Isle Royale	26	2.1		0	0.04

[8] Emission Difference Obtained from EPA Proposed FIP Table V-C.11 – Estimated Emission Reductions and Resulting Changes in Visibility Factors for Hibbing Taconite.

[9] Emission Difference Obtained from EPA Proposed FIP Table V-B.24.

Northshore Mining CAMx Emissions and Modeling Results

Northshore Emissions

Unit	EPA FIP Baseline NOx Emission (TPY)	Final FIP NOx Emission (TPY)	NOx Emission Difference (TPY)	EPA FIP Baseline SO2 Emission (TPY)	Final FIP SO2 Emission (TPY)	SO2 Emission Difference (TPY)
Power Boiler #1	676	676	0	681	681	0
Power Boiler #2	1,093	1,093	0	1,098	1,098	0
Furnace 11	386	116	270	38	38	0
Furnace 12	378	113	265	35	35	0
FURNACES	**764**	**229**	**535**	**73**	**73**	**0**
TOTAL	**2,533**	**1,998**	**535**	**1,852**	**1,852**	**0**

Northshore CAMx Results (By Unit)

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
2002						
Power Boiler #1	32	1.487	32	1.499	0	-0.012
Power Boiler #2	49	2.087	49	2.097	0	-0.010
Furnace 11	0	0.136	0	0.139	0	-0.003
Furnace 12	0	0.133	0	0.122	0	0.011
Facility Total	73	4.16	72	4.14	1	0.02
2005						
Power Boiler #1	13	0.640	13	0.654	0	-0.014
Power Boiler #2	22	0.926	23	0.911	0	0.015
Furnace 11	0	0.087	0	0.067	0	0.020
Furnace 12	0	0.082	0	0.076	0	0.006
Facility Total	51	1.67	50	1.68	1	-0.01
Voyageurs						
2002						
Power Boiler #1	1	0.196	1	0.196	0	0.000
Power Boiler #2	1	0.293	1	0.293	0	0.000
Furnace 11	0	0.016	0	0.013	0	0.003
Furnace 12	0	0.015	0	0.013	0	0.002
Facility Total	8	0.51	8	0.51	0	0.00

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Voyageurs						
2005						
Power Boiler #1	0	0.188	0	0.193	0	-0.005
Power Boiler #2	1	0.244	1	0.247	0	-0.003
Furnace 11	0	0.020	0	0.018	0	0.002
Furnace 12	0	0.021	0	0.016	0	0.004
Facility Total	6	0.47	6	0.46	0	0.01
Isle Royale						
2002						
Power Boiler #1	3	0.294	3	0.294	0	0.000
Power Boiler #2	6	0.412	6	0.408	0	0.004
Furnace 11	0	0.034	0	0.028	0	0.006
Furnace 12	0	0.037	0	0.029	0	0.008
Facility Total	16	0.75	15	0.74	1	0.00
2005						
Power Boiler #1	3	0.180	3	0.180	0	0.000
Power Boiler #2	4	0.320	4	0.322	0	-0.002
Furnace 11	0	0.036	0	0.023	0	0.013
Furnace 12	0	0.034	0	0.022	0	0.012
Facility Total	10	0.57	8	0.55	2	0.02

Northshore Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

(EPA Table C Emission Difference = 926 TPY NOx)[10]

(EPA Table B Emission Difference = 535 TPY NOx)[11]

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 98% dV
Boundary Waters	8	0.6		1	0.01
Voyageurs	4	0.3		0	0.01
Isle Royale	5	0.4		2	0.01

[10] Emission Difference Obtained from EPA Proposed FIP Table V-C.12 – Estimated Emission Reductions and Resulting Changes in Visibility Factors for Northshore Mining.

[11] Emission Difference Obtained from EPA Proposed FIP Table V-B.8; further the emission reductions in Table C exceed the FIP baseline in Table B by 142 TPY.

United Taconite (UTAC) CAMx Emissions and Modeling Results

UTAC Emissions

Unit	EPA FIP Baseline NOx Emission (TPY)	Final FIP NOx Emission (TPY)	NOx Emission Difference (TPY)[12]	EPA FIP Baseline SO2 Emission (TPY)	Final FIP SO2 Emission (TPY)[13]	SO2 Emission Difference (TPY)
Line 1	1,643	493	1,150	1,293	577	716
Line 2	3,687	1,106	2,581	2,750	1,392	1,358
TOTAL	**5,330**	**1,599**	**3,731**	**4,043**	**1,969**	**2,074**

[12]NOx emission difference was calculated using 70% emission reduction from EPA Baseline within the proposed FIP (corresponding to 1.2 lb NOx/MMBTU); to ensure maximum emission reductions were evaluated there was no change to the final FIP emissions to reflect the final FIP limit of 1.5 lb NOx/MMBTU.

[13]Final FIP SO2 Emissions were calculated using the final FIP limit of 529 lb/hr with an operating factor of 85%; this was done to maximize the emission reductions while using a reasonable operating factor

UTAC CAMx Results (By Unit)

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
2002						
Line #1	22	1.294	10	0.674	12	0.620
Line #2	45	2.744	30	1.556	15	1.189
Facility Total	76	4.22	55	2.37	21	1.85
2005						
Line #1	11	0.610	2	0.303	9	0.307
Line #2	26	1.294	15	0.678	11	0.616
Facility Total	52	2.52	34	1.57	18	0.95
Voyageurs						
2002						
Line #1	12	0.606	2	0.307	10	0.299
Line #2	26	1.452	15	0.771	11	0.681
Facility Total	42	2.10	26	1.11	16	0.99
2005						
Line #1	4	0.331	1	0.181	3	0.150
Line #2	17	0.786	6	0.446	11	0.340
Facility Total	33	1.47	14	0.76	19	0.71

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Isle Royale						
2002						
Line #1	0	0.255	0	0.117	0	0.138
Line #2	8	0.518	0	0.266	8	0.252
Facility Total	13	0.81	3	0.41	10	0.40
2005						
Line #1	0	0.163	0	0.080	0	0.083
Line #2	1	0.322	0	0.184	1	0.138
Facility Total	10	0.57	0	0.28	10	0.29

UTAC Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

(EPA Table C Emission Difference = 3,208 TPY NOx and 3,639 TPY SO2)[14]

(EPA Table B Emission Difference = 3,731 TPY NOx and 3,639 TPY SO2)[15]

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV[16]	CAMx Modeled Difference 98% dV[16]
Boundary Waters	29	1.9		20	1.40
Voyageurs	12	0.99		18	0.85
Isle Royale	14	1.16		10	0.35

[14]Emission Difference Obtained from EPA Proposed FIP Table V-C.13 – Estimated Emission Reductions and Resulting Changes in Visibility Factors for United Taconite.

[15]Emission Difference Obtained from EPA Proposed FIP Table V-B.14 (SO2) and V-B.17 (NOx) – NOx reductions are not consistent

[16]Baseline – final FIP Emission Reductions -> 3,731 TPY NOx and 2,074 TPY SO2

The United Taconite comparison table above does not provide an “apples to apples” comparison. As noted, the EPA estimated visibility benefits include more SO2 emission reductions (proposed FIP) than are included in the final FIP. This table was amended to include the revised SO2 emission reductions using EPA’s apparent methodology within the proposed FIP. The EPA scalars (proposed FIP – Table V – C.9) were applied for each pollutant using the corrected emission reduction for NOx and the revised emission reduction for SO2. Then, those resultants were averaged for each of the Class I areas to obtain the amended EPA estimates below to provide for the appropriate comparison of EPA’s method.

Amended UTAC Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

Final FIP Emission Difference = 3,731 TPY NOx and 2,074 TPY SO2

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 98% dV
Boundary Waters	22	1.6		20	1.40
Voyageurs	10	0.8		18	0.85
Isle Royale	14	1.1		10	0.35

As discussed above, the SO4 and NO3 visibility benefits were combined by EPA. The following tables provide a modeled comparison of the impacts sorted by SO4 and NO3 on a line-specific basis, then combined for both lines. The sulfate impact was derived by sorting the visibility impacts at each receptor from each scenario by maximum sulfate contribution for each line. Likewise, the nitrate impact was derived by sorting the visibility impacts at each receptor from each scenario by maximum nitrate contribution for each line. Then, the results were summed for both lines to obtain the overall UTAC impact by pollutant. In nearly all circumstances, this will overestimate the impact of the NO_X control. This is due to the impact from the sulfate reductions that drives the total visibility impact with a much smaller percentage from the nitrate reductions. When the nitrate impact is maximized by the sorting technique, the overall impact on the same day could be very small (e.g. nitrate = 0.15 dV; total = 0.20 dV) and would not show up as part of the overall visibility change (see Line 2 – 2002 Boundary Waters results).

UTAC Line 1 – Pollutant Specific Modeling Results

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
2002						
Line #1 – NO3	0	0.106	0	0.059	0	0.047
Line #1 – SO4	22	1.294	10	0.674	12	0.620
Line #1 – All	22	1.294	10	0.674	12	0.620
2005						
Line #1 – NO3	0	0.136	0	0.083	0	0.053
Line #1 – SO4	8	0.571	2	0.280	6	0.291
Line #1 – All	11	0.610	2	0.303	9	0.307
Voyageurs						
2002						
Line #1 – NO3	0	0.040	0	0.017	0	0.023
Line #1 – SO4	11	0.582	2	0.301	9	0.281
Line #1 – All	12	0.606	2	0.307	10	0.299
2005						
Line #1 – NO3	0	0.048	0	0.027	0	0.021
Line #1 – SO4	4	0.330	1	0.155	3	0.175
Line #1 – All	4	0.331	1	0.181	3	0.150
Isle Royale						
2002						
Line #1 – NO3	0	0.033	0	0.015	0	0.018
Line #1 – SO4	0	0.216	0	0.104	0	0.112
Line #1 – All	0	0.255	0	0.117	0	0.138
2005						
Line #1 – NO3	0	0.026	0	0.011	0	0.015
Line #1 – SO4	0	0.150	0	0.072	0	0.078
Line #1 – All	0	0.163	0	0.080	0	0.083

UTAC Line 2 – Pollutant Specific Modeling Results

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
2002						
Line #2 – NO3	1	0.237	0	0.090	1	0.147
Line #2 – SO4	44	2.679	28	1.547	16	1.132
Line #2 – All	45	2.744	30	1.556	15	1.189
2005						
Line #2 – NO3	1	0.195	0	0.091	1	0.104
Line #2 – SO4	25	1.196	15	0.659	10	0.539
Line #2 – All	26	1.294	15	0.678	11	0.616
Voyageurs						
2002						
Line #2 – NO3	0	0.104	0	0.031	0	0.073
Line #2 – SO4	25	1.446	15	0.768	10	0.678
Line #2 – All	26	1.452	15	0.771	11	0.681
2005						
Line #2 – NO3	0	0.083	0	0.033	0	0.050
Line #2 – SO4	16	0.773	6	0.436	10	0.337
Line #2 – All	17	0.786	6	0.446	11	0.340
Isle Royale						
2002						
Line #2 – NO3	0	0.054	0	0.018	0	0.036
Line #2 – SO4	7	0.469	0	0.245	7	0.224
Line #2 – All	8	0.518	0	0.266	8	0.252
2005						
Line #2 – NO3	0	0.046	0	0.016	0	0.030
Line #2 – SO4	1	0.319	0	0.166	1	0.153
Line #2 – All	1	0.322	0	0.184	1	0.138

UTAC Comparison of Sulfate-Specific Amended EPA Final FIP Visibility Improvement Estimates with CAMx Modeling Analyses

Final FIP Emission Difference = 2,074 TPY SO2

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 98% dV
Boundary Waters	14	1.0		22	1.29
Voyageurs	6	0.5		16	0.74
Isle Royale	8	0.6		4	0.28

UTAC Comparison of Nitrate-Specific Amended EPA Final FIP Visibility Improvement Estimates with CAMx Modeling Analyses

Final FIP Emission Difference = 3,731 TPY NOx

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 98% dV
Boundary Waters	31	2.3		1	0.18
Voyageurs	15	1.1		0	0.08
Isle Royale	20	1.6		0	0.05

The maximum 98th percentile NO3 impact when combining both line emission reductions is 0.18 dV, while the maximum 98th percentile SO4 impact for both lines is 1.29 dV. Based on these results, it is evident that the SO4 impact on the Class I areas provides the vast majority of the predicted CAMx estimates of visibility improvement. This finding is consistent with MPCA's original finding for BART in the 2009 SIP that NOx emission reductions do not provide substantive visibility improvement.

Tilden Mining CAMx Emissions and Modeling Results

Tilden Emissions

Unit	EPA FIP Baseline NOx Emission (TPY)	Final FIP NOx Emission (TPY)	NOx Emission Difference (TPY)	EPA FIP Baseline SO2 Emission (TPY)	Final FIP SO2 Emission (TPY)	SO2 Emission Difference (TPY)
Line 1	4,613	1,384	3,229	1,153	231	922
TOTAL	**4,613**	**1,384**	**3,229**	**1,153**	**231**	**922**

Tilden CAMx Results (By Unit)

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
2002						
Line #1	0	0.141	0	0.037	0	0.104
2005						
Line #1	0	0.097	0	0.042	0	0.055
Voyageurs						
2002						
Line #1	0	0.042	0	0.011	0	0.031
2005						
Line #1	0	0.041	0	0.010	0	0.031
Isle Royale						
2002						
Line #1	1	0.300	0	0.094	1	0.206
2005						
Line #1	0	0.211	0	0.070	0	0.141

Tilden Line 1 – Pollutant Specific Modeling Results

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
2002						
Line #1 – NO3	0	0.031	0	0.013	0	0.018
Line #1 – SO4	0	0.102	0	0.022	0	0.080
Line #1 – All	0	0.141	0	0.037	0	0.104
2005						
Line #1 – NO3	0	0.045	0	0.042	0	0.003
Line #1 – SO4	0	0.087	0	0.019	0	0.068
Line #1 – All	0	0.097	0	0.042	0	0.055
Voyageurs						
2002						
Line #1 – NO3	0	0.002	0	0.001	0	0.001
Line #1 – SO4	0	0.041	0	0.011	0	0.030
Line #1 – All	0	0.042	0	0.011	0	0.031
2005						
Line #1 – NO3	0	0.005	0	0.003	0	0.002
Line #1 – SO4	0	0.039	0	0.008	0	0.031
Line #1 – All	0	0.041	0	0.010	0	0.031
Isle Royale						
2002						
Line #1 – NO3	0	0.084	0	0.038	0	0.046
Line #1 – SO4	1	0.197	0	0.052	1	0.145
Line #1 – All	1	0.300	0	0.094	1	0.206
2005						
Line #1 – NO3	0	0.043	0	0.047	0	-0.004
Line #1 – SO4	0	0.176	0	0.040	0	0.136
Line #1 – All	0	0.211	0	0.070	0	0.141

Attachment 3

2012 AECOM Report

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

Robert Paine and David Heinold, AECOM

September 28, 2012

Executive Summary

This report reviews several aspects of the visibility assessment that is part of any Best Available Retrofit Technology (BART) assessment. The crux of this analysis focuses upon two opportunistic emission reductions that have resulted in no perceptible visibility benefits, while a straightforward application of EPA's modeling procedures would predict a substantial visibility benefit. These actual emission reduction cases include the shutdown of the Mohave Generating Station (and minimal visibility effects at the Grand Canyon) as well as the economic slowdown that affected emissions from the taconite plants in Minnesota in 2009.

There are several reasons why there is an inconsistency between the real world and the modeling results:

- Natural background conditions, which are used in the calculation of haze impacts due to anthropogenic emissions, are mischaracterized as too clean, which exaggerates the impact of emission sources. Overly clean natural conditions can erroneously indicate that some states are missing the 2018 milestone for achieving progress toward an impossible goal by the year 2064.
- The chemistry in the current EPA-approved version of CALPUFF as well as regional photochemical models overestimates winter nitrate haze, especially with the use of high ammonia background concentrations. There are other CALPUFF features that result in overpredictions of all pollutant concentrations that are detailed in this report. Therefore, BART emission reductions will be credited with visibility modeling for more visibility improvements than will really occur. We recommend that EPA adopt CALPUFF v. 6.42, which includes substantial improvements in the chemistry formulation. We also recommend the use of seasonally varying ammonia background concentrations, in line with observations and the current capabilities of CALPUFF.
- In addition to CALPUFF, the use of regional photochemical models results in significant nitrate haze overpredictions for Minnesota Class I area predictions.
- The modeled base case modeled scenario is always a worst-case emission rate which is assumed to occur every day. The actual emissions are often lower, and so the modeled improvement is an overestimate.

Impacts of the taconite plants' NO_X emissions are confined to winter months by the unique chemistry for nitrate particle formation. During these months, the attendance at the parks is greatly reduced by the closure of significant portions of the parks and the inability to conduct boating activities on frozen water bodies. In the case of Isle Royale National Park, there is total closure in the winter, lasting for 5 ½ months. The BART rule makes a provision for the consideration of such seasonal impacts. The imposition of NO_X controls year-round would not only have minimal benefits in the peak visitation season of summer, but also could lead to increases in haze due to the increased power requirements (and associated emissions) needed for their operation, an effect that has not been considered in the visibility modeling.

An analysis of the impact of the visibility impacts of Minnesota BART sources on Michigan's Class I areas, as well as the impacts of Michigan sources on Minnesota's Class I areas indicates that the effects on the other state's Class I areas is minor. The taconite plant emissions are not expected to interfere with the ability of other states to achieve their required progress under the Regional Haze Rule.

Introduction

Best Available Retrofit Technology (BART) is part of the Clean Air Act (Appendix Y of 40 CFR Part 51) as a requirement related to visibility and the 1999 Regional Haze Rule (RHR)[1] that applies to existing stationary sources. Sources eligible for BART were those from 26 source categories with a potential to emit over 250 tons per year of any air pollutant, and that were placed into operation between August 1962 and August 1977. Final BART implementation guidance for regional haze was published in the Federal Register on July 6, 2005[2].

The United States Environmental Protection Agency (EPA) has issued a proposed rule[3] to address BART requirements for taconite plants in Minnesota and Michigan that involves emission controls for SO_2 and NO_X. This document addresses the likely visibility impact of taconite plant emissions, specifically NO_X emissions, for impacts at Prevention of Significant Deterioration (PSD) Class I areas that the RHR addresses.

Locations of Emission Sources and PSD Class I Areas

Figure 1 shows the location of BART-eligible taconite plants in Minnesota and Michigan addressed in EPA's proposed rule, as well as Class I areas within 500 km of these sources. In most applications of EPA's preferred dispersion model for visibility impacts, CALPUFF[4], the distance limitation is 200-300 km because of the overprediction tendencies[5] for further distances. The overprediction occurs because of extended travel times that often involve at least a full day, during which there can be significant wind shear influences on plume spreading that the model and the meteorological wind field does not accommodate. With larger travel distances, there are higher uncertainties in the predictions of any model, either CALPUFF or a regional photochemical model. Therefore, a reasonable upper limit for establishing the impact of the taconite sources would be 500 km, with questionable results beyond 200-300 km from the source. In this case, the Class I areas involved are those shown in Figure 1. All other PSD Class I areas are much further away. It is noteworthy that EPA's visibility improvement assessment considered only three Class I areas: Voyageurs National Park, Boundary Waters Canoe Area Wilderness, and Isle Royale National Park.

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[1] Regional Haze Regulations; Final Rule. *Federal Register*, *64*, 35713-35774. (July 1, 1999).

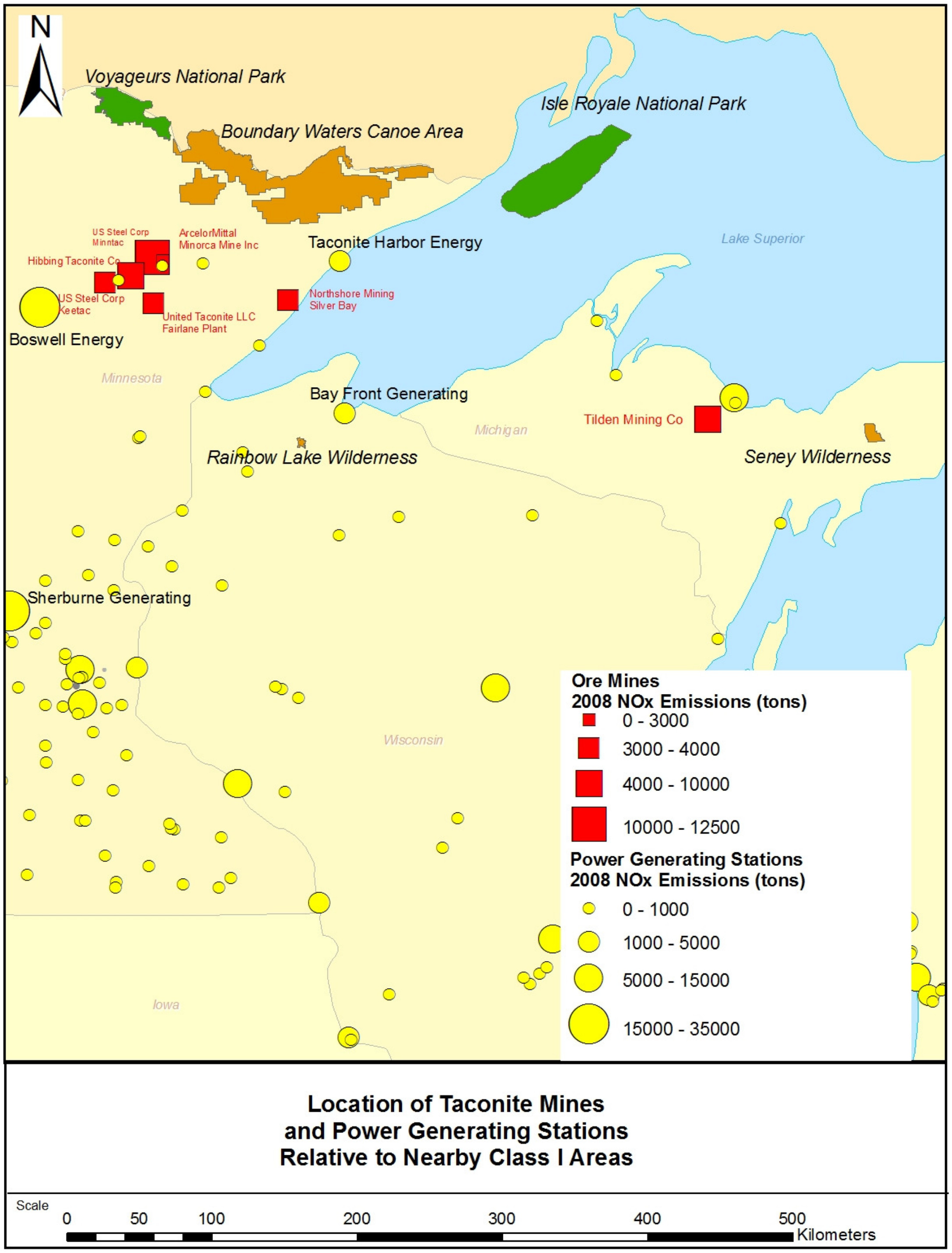
[2] Federal Register. EPA Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule. Federal Register, Vol. 70. (July 6, 2005)

[3] 77FR49308, August 15, 2012.

[4] CALPUFF Dispersion Model, 2000. http://www.epa.gov/scram001 (under 7th Modeling Conference link to Earth Tech web site).

[5] As documented in Appendix D of the IWAQM Phase 2 document, available at www.epa.gov/scram001/7thconf/calpuff/**phase2**.pdf.

Figure 1 Location of Emission Sources Relative To PSD Class I Areas in Minnesota and Michigan



Overprediction Tendency of Visibility Assessment Modeling for BART Emission Reductions

A particularly challenging part of the BART process is the lack of well-defined criteria for determining whether a proposed emission reduction is sufficient, because the criteria for determining BART are somewhat subjective in several aspects, such as what controls are cost-effective and the degree to which the related modeled reductions in haze are sufficient. In addition, the calculations of the visibility improvements, which are intrinsic to establishing the required BART controls, are subject to considerable uncertainty due both to the inherent uncertainty in model predictions and model input parameters. Alternative approaches for applying for technical options and chemistry algorithms in the United States Environmental Protection Agency's (EPA's) preferred CALPUFF model can result in a large range in the modeled visibility improvement. The degree of uncertainty is especially large when NO_X emission controls are considered as a BART option because modeling secondary formation of ammonium nitrate is quite challenging. Accurately modeling the effects of NO_X controls on visibility is very important because they are often very expensive to install and operate. As a collateral effect that needs to be taken into account for BART decisions, such controls can also complicate energy efficiency objectives and strategies to control greenhouse gases and other pollutants. In this paper we discuss why EPA's preferred application of CALPUFF would likely overestimate the predicted visibility impact of emissions, especially NO_X, and the associated effectiveness of NO_X emission controls. Overestimates of the benefits of emissions reduction are evident from the following observations, which are discussed in this document:

- Natural background extinction used in CALPOST to calculate a source's haze impacts is underestimated, which has the effect of exaggerating the impact, which is computed relative to these defined conditions. Natural conditions also dictate how well each state is adhering to the 2018 milestone for achieving progress toward this goal by the year 2064. If the specification of natural conditions is underestimated to the extent that it is not attainable regardless of contributions from U.S. anthropogenic sources, then some states will be penalized for not achieving sufficient progress toward an impossible goal. Appendix A discusses this point in more detail.

- The chemistry in the current EPA-approved version of CALPUFF overestimates winter nitrate haze, especially in conjunction with the specification of high ammonia background concentrations. This conservatism is exacerbated by CALPUFF features that result in overpredictions of all pollutant concentrations. Therefore, CALPUFF modeling will credit BART emission reductions with more visibility improvements than will really occur.

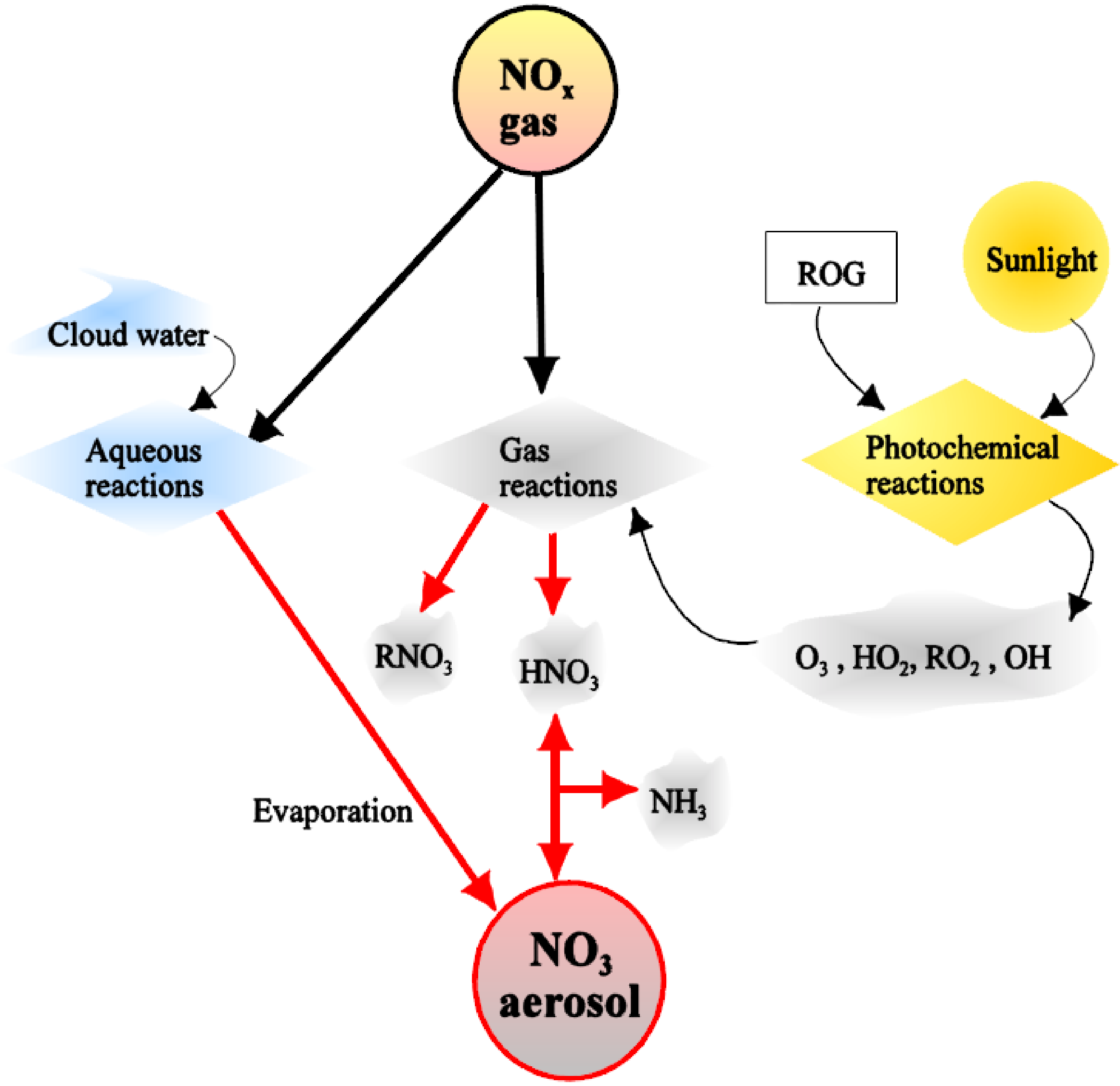
- There are examples where actual significant emission reductions have occurred, where CALPUFF modeling as conducted for BART would predict significant visibility improvements, but no perceptive changes in haze occurred.

Visibility Impact of NO_X Emissions – Unique Aspects and Seasonality

The oxidation of NO_X to total nitrate (TNO_3) depends on the NO_X concentration, ambient ozone concentration, and atmospheric stability. Some of the TNO_3 is then combined with available ammonia in the atmosphere to form ammonium nitrate aerosol in an equilibrium state with HNO_3 gas that is a function

of temperature, relative humidity, and ambient ammonia concentration, as shown in Figure 2[6]. It is important to realize that both CALPUFF and regional photochemical models tend to overpredict nitrate formation, especially in winter. A more detailed discussion of this issue is provided in Appendix B.

Figure 2 CALPUFF II NO_x Oxidation



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[6] Figure 2-32 from CALPUFF Users Guide, available at http://www.src.com/calpuff/download/CALPUFF_UsersGuide.pdf.

In CALPUFF, total nitrate ($TNO_3 = HNO_3 + NO_3$) is partitioned into each species according to the equilibrium relationship between gaseous HNO_3 and NO_3 aerosol. This equilibrium is a function of ambient temperature and relative humidity. Moreover, the formation of nitrate strongly depends on availability of NH_3 to form ammonium nitrate. A summary of the conditions affecting nitrate formation is provided below:

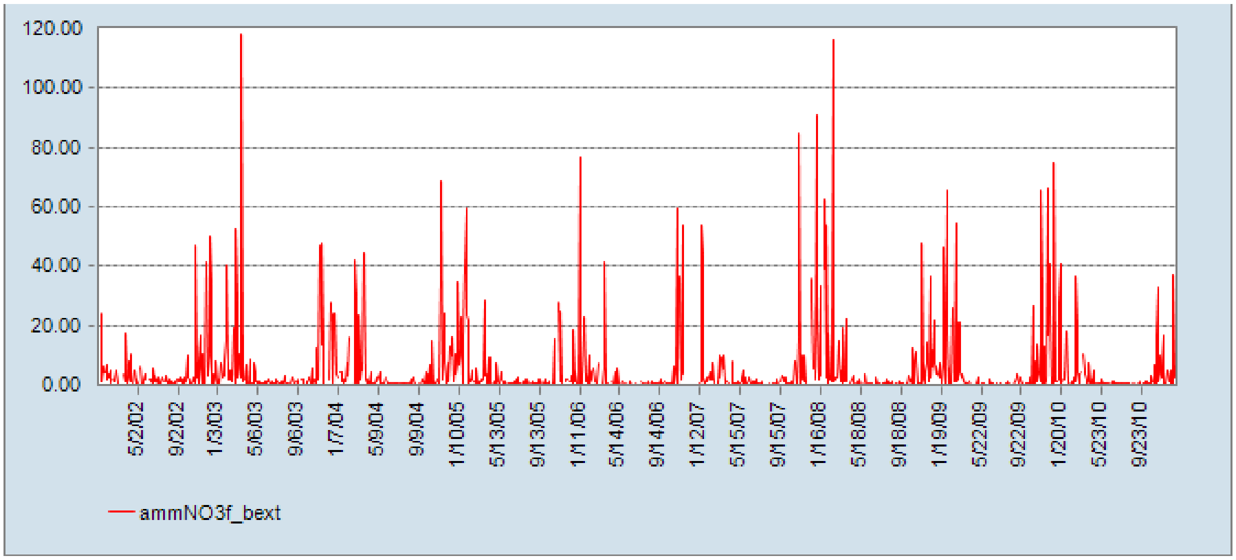
- Colder temperature and higher relative humidity create favorable conditions to form nitrate particulate matter, and therefore more ammonium nitrate is formed;
- Warm temperatures and lower relative humidity create less favorable conditions to form nitrate particulate matter, and therefore less ammonium nitrate is formed;
- Sulfate preferentially scavenges ammonia over nitrates.

For this BART analysis, the effects of temperature and background ammonia concentrations on the nitrate formation are the key to understanding the effects of various NO_X control options. For parts of the country where sulfate concentrations are relatively high and ammonia emissions are quite low, the atmosphere is likely to be in an ammonia-limited regime relative to nitrate formation. Therefore, NO_X emission controls are not very effective in improving regional haze, especially if there is very little ambient ammonia available.

In many cases, the BART visibility assessments ignore the haze increases that occur due to the additional power generation required to operate the control equipment. For NO_X controls, for example, the warm season emissions have minimal visibility impact, but the associated SO_2 emissions from the power generation required to run the controls will increase sulfate haze. These effects have not been considered in the visibility assessment modeling.

It is evident from haze composition plots available from Interagency Monitoring of Protected Visual Environments (IMPROVE) monitors that nitrate haze is confined to winter months. This is clearly shown in Figure 3, which is a timeline of nitrate haze extinction from Boundary Waters Canoe Area Wilderness. Similar patterns are evident for the other Class I areas plotted in Figure 1. The impact of NO_X emissions during the non-winter months (e.g., April through October) is very low.

Figure 3 Boundary Water Canoe Area Wilderness Ammonium Nitrate Extinction, 2002-2010



The occurrence of significant nitrate haze only in the winter months has implications for the effectiveness of haze reductions relative to park attendance. The BART Rule addresses the seasonal issue as follows: “Other ways that visibility improvement may be assessed to inform the control decisions would be to examine distributions of the daily impacts, determine if the time of year is important (e.g., high impacts are occurring during tourist season) . . .“

In this case, the high nitrate impacts are not occurring during the tourist season, especially for the water-dominant Class I areas in Minnesota (Voyageurs and Boundary Waters) that freeze in winter. In fact, for Voyageurs National Park, the typical monthly attendance[7] for an off-season month (November) is only 0.2% that of a peak-season month (July). This is obviously due in part to the brutal winter weather in northern Minnesota (and Michigan) and the lack of boating access to frozen water bodies.

Operations at the Michigan Class I areas in winter are even more restricted. Isle Royale National Park is one of the few national parks to totally close[8] during the winter (generally, during the period of November 1 through April 15). The closure is due to the extreme winter weather conditions and difficulty of access from the mainland across a frozen Lake Superior, for the protection of wildlife, and for the safety and protection of potential visitors. Due to this total closure, there is very little nitrate haze impact in this park during the seasons of the year that it is open, and haze issues for Isle Royale National Park will not be further considered in this report.

The Seney Wilderness Area Visitor Center is open[9] only during the period of May 15th to mid-October. Various trails are generally only open during the same period. The tour loops are closed in the fall, winter, and spring to allow migrating and nesting birds a place to rest or nest undisturbed, and because of large amounts of snow. Although portions of the park are open in the winter, the visitation is greatly reduced due to no visitor center access, no trail or tour loop access, and the severe weather.

Effect of 2009 Recession on Haze in Affected PSD Class I Areas

The effect on haze of a significant (50%) emission reduction from the taconite plants that actually occurred in early 2009 and lasted throughout calendar year 2009 is discussed in this section. This emission reduction was not due to environmental regulations, but rather economic conditions, and affected all pollutants being emitted by the collective group of Minnesota taconite plants, as well as regional power production that is needed to operate the taconite plants.

The annual taconite production[10] from the Minnesota taconite plants in recent years is plotted in Figure 4, along with annual average nitrate concentrations at the nearest Class I area, Boundary Waters Canoe Area (BWCA). The figure shows that the nitrate measured in the park did not respond to the reduction in emissions from the taconite plants. Figures 5 and 6 show the time series[11] of nitrate and sulfate haze in

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[7] As documented at http://www.gorp.com/parks-guide/voyageurs-national-park-outdoor-pp2-guide-cid9423.html.

[8] As noted at http://www.nps.gov/isro/planyourvisit/hours.htm.

[9] As noted at http://www.fws.gov/midwest/seney/visitor_info.html.

[10] Production data is available from taxes levied on taconite production, and the data was supplied by BARR Engineering through a personal communication with Robert Paine of AECOM.

[11] Available from the VIEWS web site at http://views.cira.colostate.edu/web/.

the BWCA over the past several years. Figures for other affected Class I areas (Voyageurs, Seney, and Isle Royale) are shown in Appendix C.

Figure 4 Minnesota Taconite Production and BWCA Nitrate Concentrations

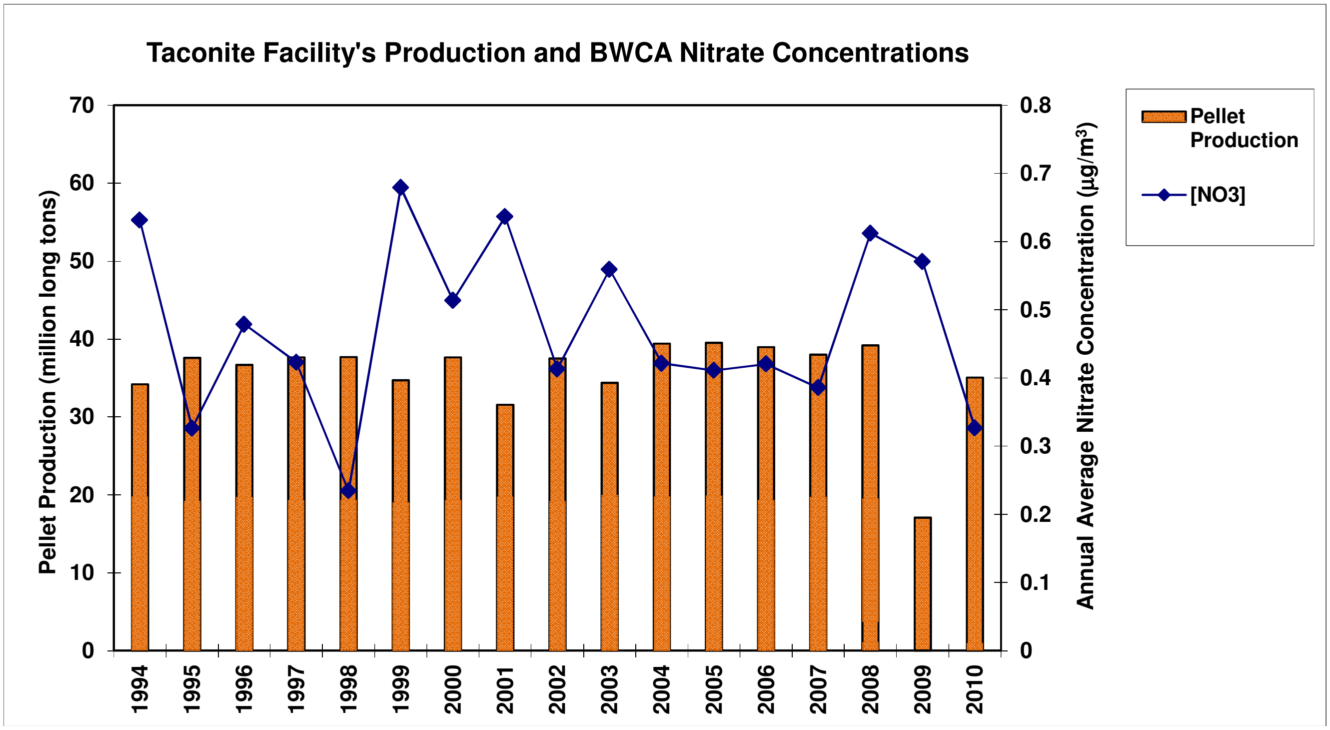


Figure 5 Time Series of Nitrate Haze at Boundary Waters Canoe Area (2002-2010)

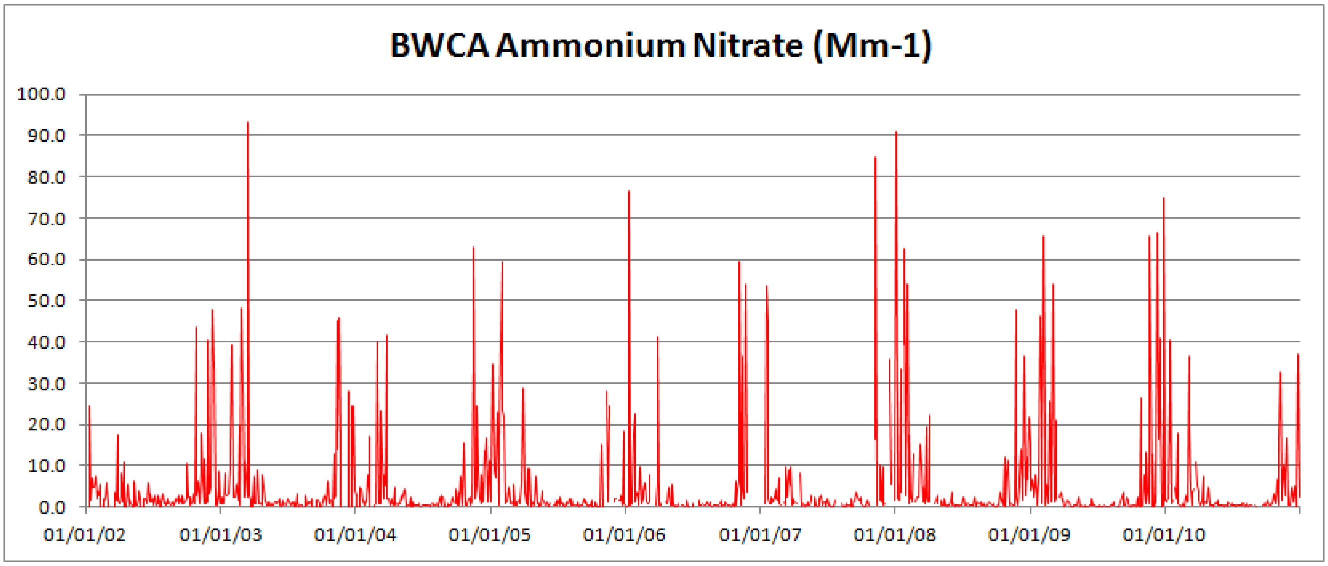
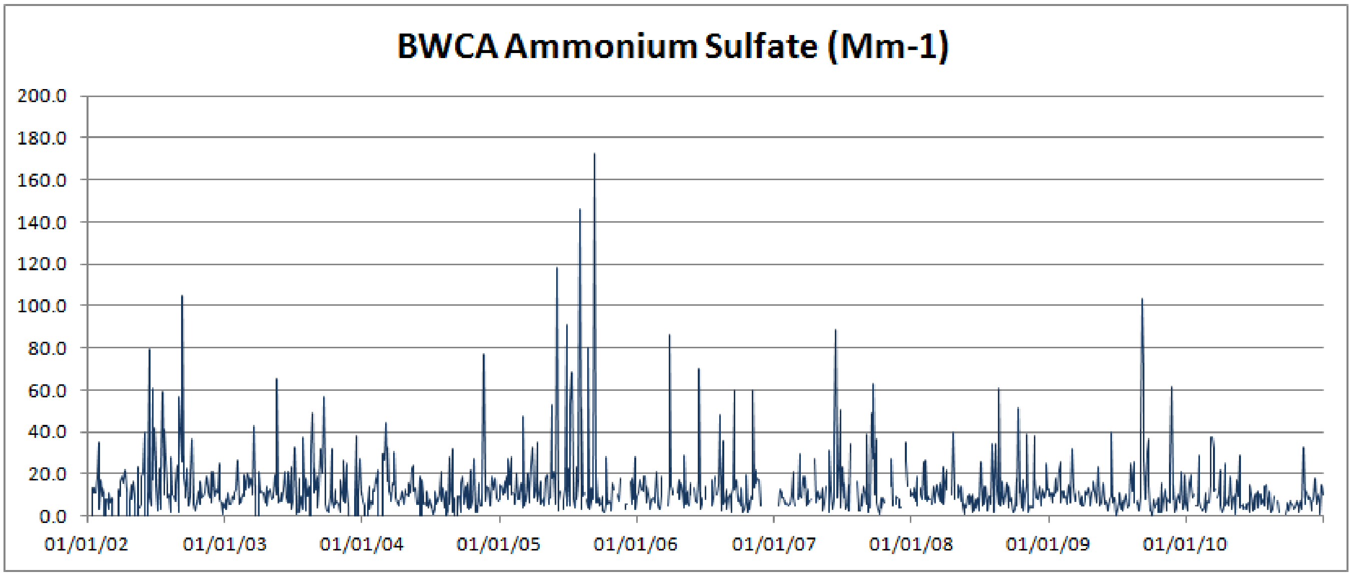


Figure 6 Time Series of Sulfate Haze at Boundary Waters Canoe Area (2002-2010)



It is evident from this information that the haze levels in BWCA did not, in general, decrease during 2009, and were therefore unaffected by emission reductions associated with the taconite production slowdown. It is noteworthy that peak events during mid-2009 in sulfate haze at BWCA when very little taconite production was occurring clearly indicate that minimal haze reduction would likely be associated with taconite plant emission reductions.

It is instructive to review the haze composition time series plots for BWCA for 2008, 2009, and 2010, as shown in Figures 7, 8, and 9.

Figure 7 Haze Composition Figure for Boundary Waters Canoe Area Wilderness, 2008

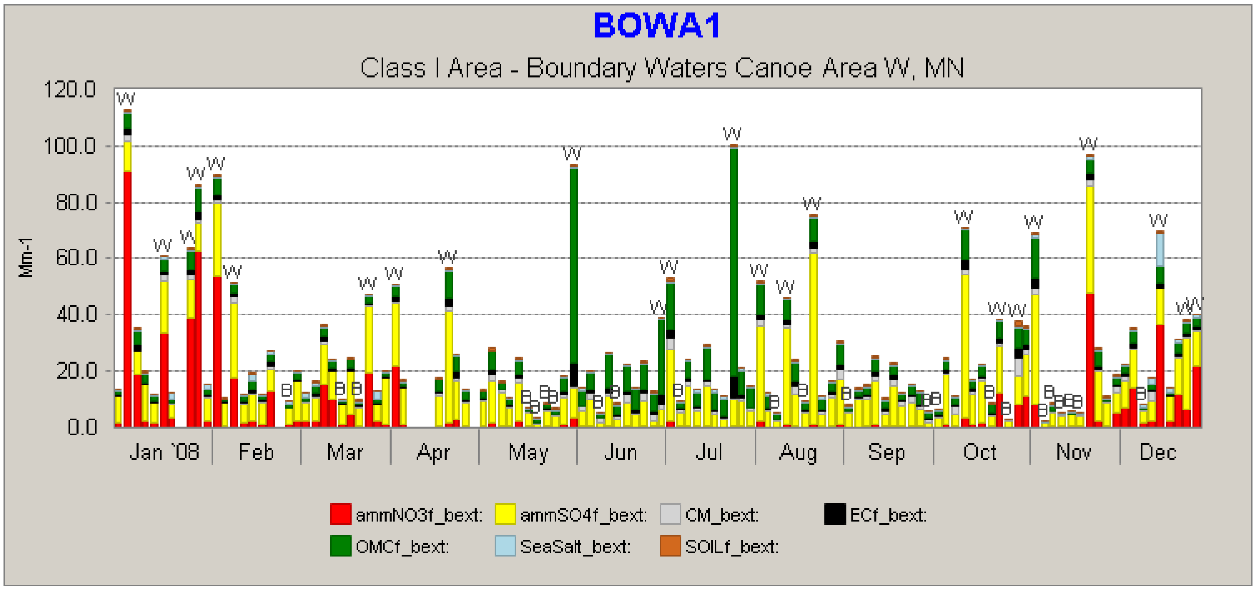


Figure 8 Haze Composition Figure for Boundary Waters Canoe Area Wilderness, 2009

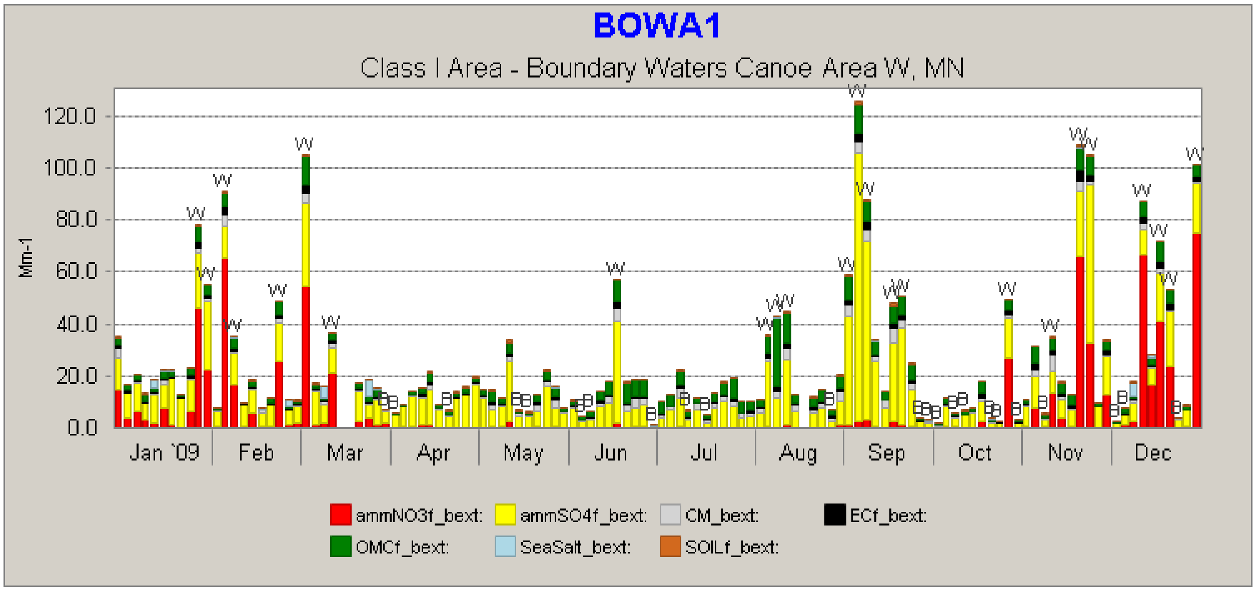
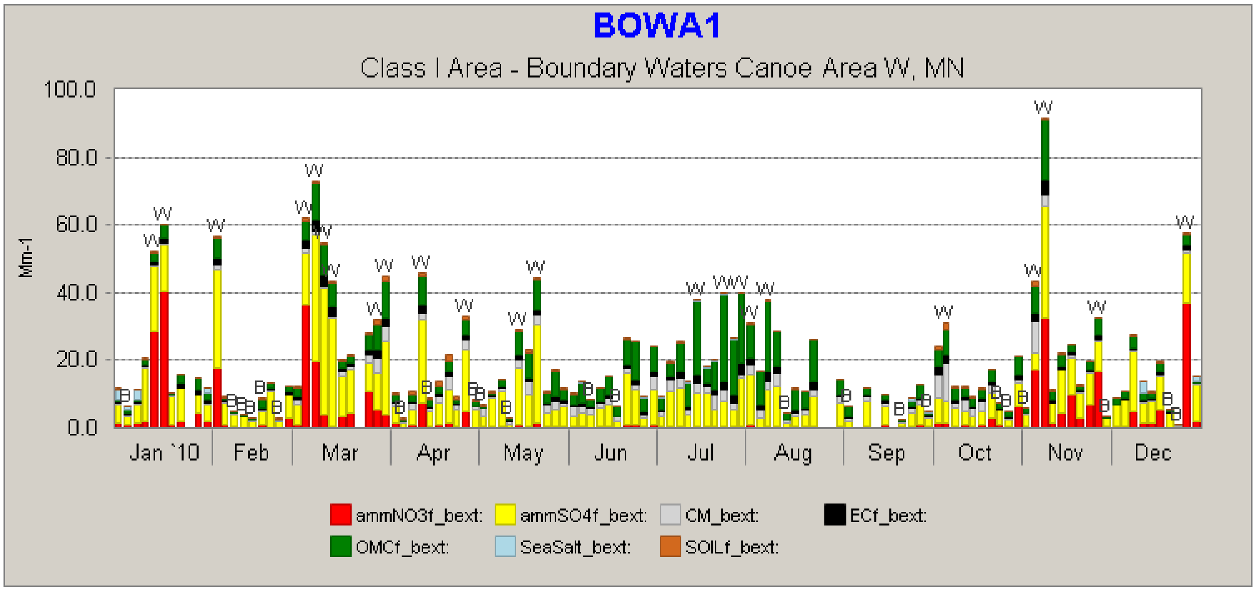


Figure 9 Haze Composition Figure for Boundary Waters Canoe Area Wilderness, 2010



As has been mentioned above, it is evident that the nitrate haze (red bars) is only important during the colder months (November through March). It is also evident that haze from forest fires (green bars) is predominant in the warm weather months, but varies from year to year according to the frequency of wildfires. For example, 2008 was a year of high occurrences of wildfires, while 2009 saw a low frequency, and 2010 was more normal.

The curtailment of taconite plant activity lasted from early 2009 through December 2009, peaking in the summer of 2009. Even so, we see the highest sulfate haze days (yellow bars) in September 2009 when taconite production was half of normal activity. Also, we note high nitrate haze days late in 2009 with the taconite plant curtailment that are comparable in magnitude to full taconite production periods in 2008. We also note that after the taconite plants went back to full production in 2010, the haze levels dropped, apparently due to emissions from other sources and/or states.

These findings suggest that reduction of emissions from the taconite plants will likely have minimal effects on haze in the nearby Class I areas. The fact that the various plants are distributed over a large area means that individual plumes are isolated and generally do not combine with others.

At least one other emission reduction opportunity to determine the effect on visibility improvement has occurred; this is related to the shutdown of the Mohave Generating Station in 2005, and its effect upon visibility in the Grand Canyon National Park. The discussion in Appendix D indicates that although CALPUFF modeling predicted substantial visibility benefits, very little change has occurred since 2005.

Other reasons that visibility assessment models such as CALPUFF could overpredict impacts are listed below.

1) The CALPUFF base case modeled scenario is always a worst-case emission rate which is assumed to occur every day. The actual emissions are often lower, and so the modeled improvement is an overestimate.

2) The way that the predicted concentrations are accounted for in the CALPOST output overstate the impact for even the case where the CALPUFF predictions are completely accurate. The way that CALPOST works is that the peak 24-hour prediction <u>anywhere</u> in a Class I area is the only information saved for each predicted day. The predicted impact for each day is effectively assumed to be a) always in the same place; and b) in all portions of the Class I area. Therefore, the 98th percentile day's prediction could be comprised of impacts in 8 different places that are all erroneously assumed to be co-located.

3) CALPUFF does not simulate dispersion and transport accurately over a full diurnal cycle, during which significant wind direction shear can occur (and is not properly accounted for by CALPUFF). This can result in plumes that are more cohesive than actually occur.

4) As discussed above, it is well established that nitrate predictions are often overstated by CALPUFF v. 5.8, especially in winter.

5) Natural conditions as input to CALPOST are not attainable, and their use will exaggerate the simulated visibility impacts of modeled emissions.

<u>Interstate Non-Interference with Regional Haze Rule SIPs from Taconite Plant Emissions</u>

An issue that is a recurring one for a number of state implementation plans (SIPs) is whether emissions from one state can interfere with haze reduction plans for downwind states. For Minnesota, it would be expected that emission reductions undertaken to reduce haze in Minnesota Class I areas (Voyageurs and Boundary Waters) would also act to reduce haze in other Class I areas. In the case of Minnesota's

taconite plant emissions, earlier discussions of the potentially affected Class I areas indicated that only the Class I areas in northern Michigan (Isle Royale National Park and Seney Wilderness Area) are close enough and in a general predominant wind direction to merit consideration. The closer of these two parks, Isle Royale, is closed to the public from November 1 through April 15, and haze effects there would not be affected by NO_X emissions because those effects are only important in the winter. Since Minnesota's Class I areas are located generally upwind of Michigan sources, the impact of Michigan sources on these Class I areas is expected to be small. This is confirmed in the Particulate Matter Source Apportionment Technology (PSAT) plots shown below.

Regional photochemical modeling studies[12] conducted by the CENRAP Regional Planning Organization, of which Minnesota is a part, shows contributions of various states as well as international contributions for haze impacts in the Michigan Class I areas. Relevant figures from the Iowa RHR SIP report for 2018 emission inventory haze impacts are reproduced below for Isle Royale National Park (Figure 10) and Seney Wilderness Area (Figure 11).

The modeling conducted for this analysis, using CAMx, shows that the relative contribution to haze for all Minnesota sources to sulfate haze in Isle Royale National Park is low, consisting of only 10% of the sulfate haze. The effect of 2018 emissions from Minnesota sources at the more distant Seney Wilderness Area is even lower, with the state's emissions ranking 9th among other jurisdictions analyzed for this Class I area. Therefore, it is apparent that Minnesota sources, and certainly the subset including taconite plants, would not be expected to interfere with other state's progress toward the 2018 milestone associated with the Regional Haze Rule.

Figures 12 and 13, reproduced from the Iowa RHR SIP report for Boundary Waters and Voyageurs, respectively, indicate that Michigan sources rank 11th and 12th, respectively, for haze impacts in these two areas for projected 2018 emissions. Therefore, as expected, Michigan sources are not expected to interfere with Minnesota's RHR SIP for progress in 2018.

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[12] See, for example, the Iowa State Implementation Plan for Regional Haze report at http://www.iowadnr.gov/portals/idnr/uploads/air/insidednr/rulesandplanning/rh_sip_final.pdf, Figures 11.3 and 11.4.

Figure 10 PSAT Results from CENRAP CAMx Modeling for Isle Royale National Park

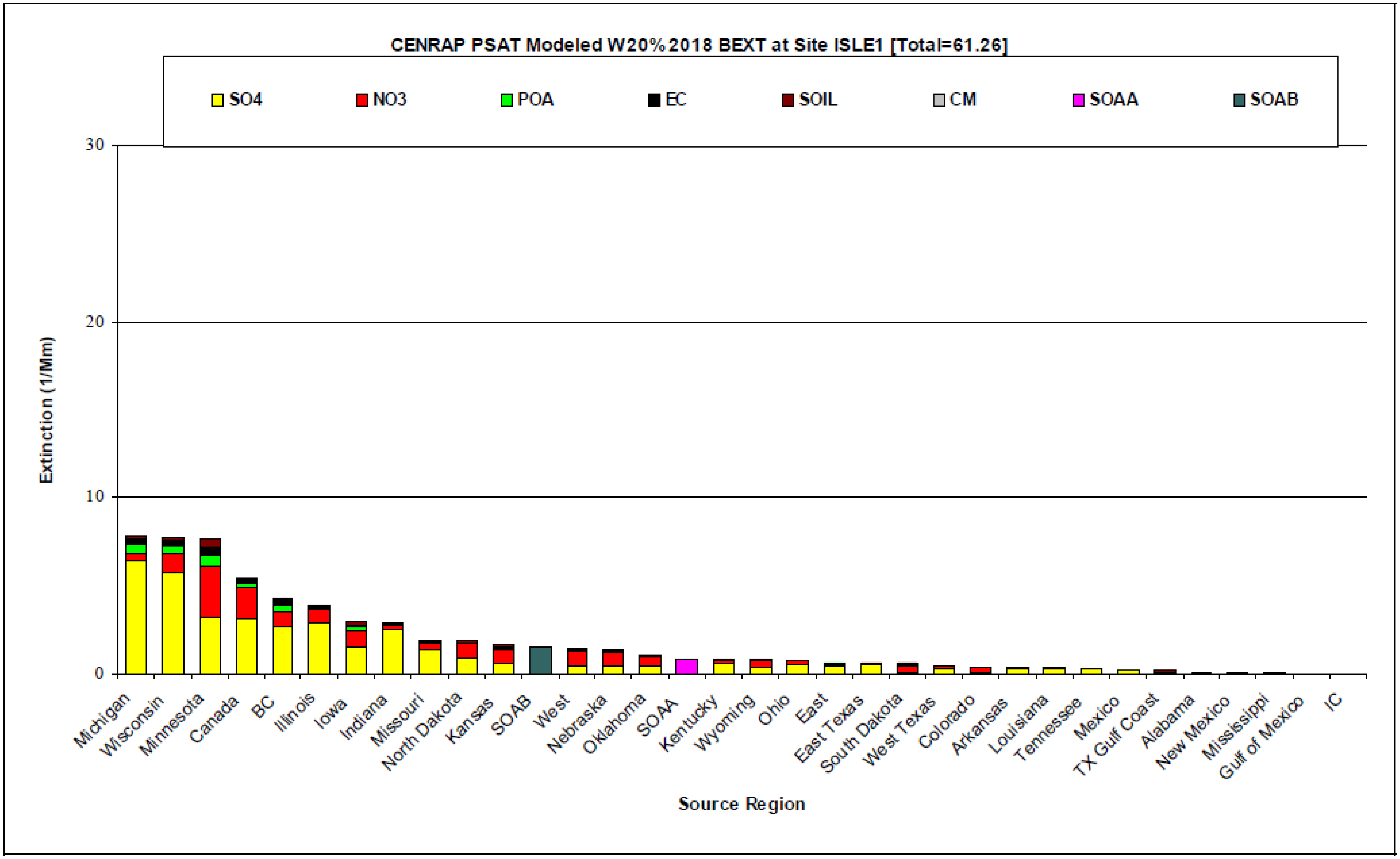


Figure 11.3. Source apportion contributions by region and pollutant to ISLE in 2018.

Figure 11 PSAT Results from CENRAP CAMx Modeling for Seney Wilderness Area

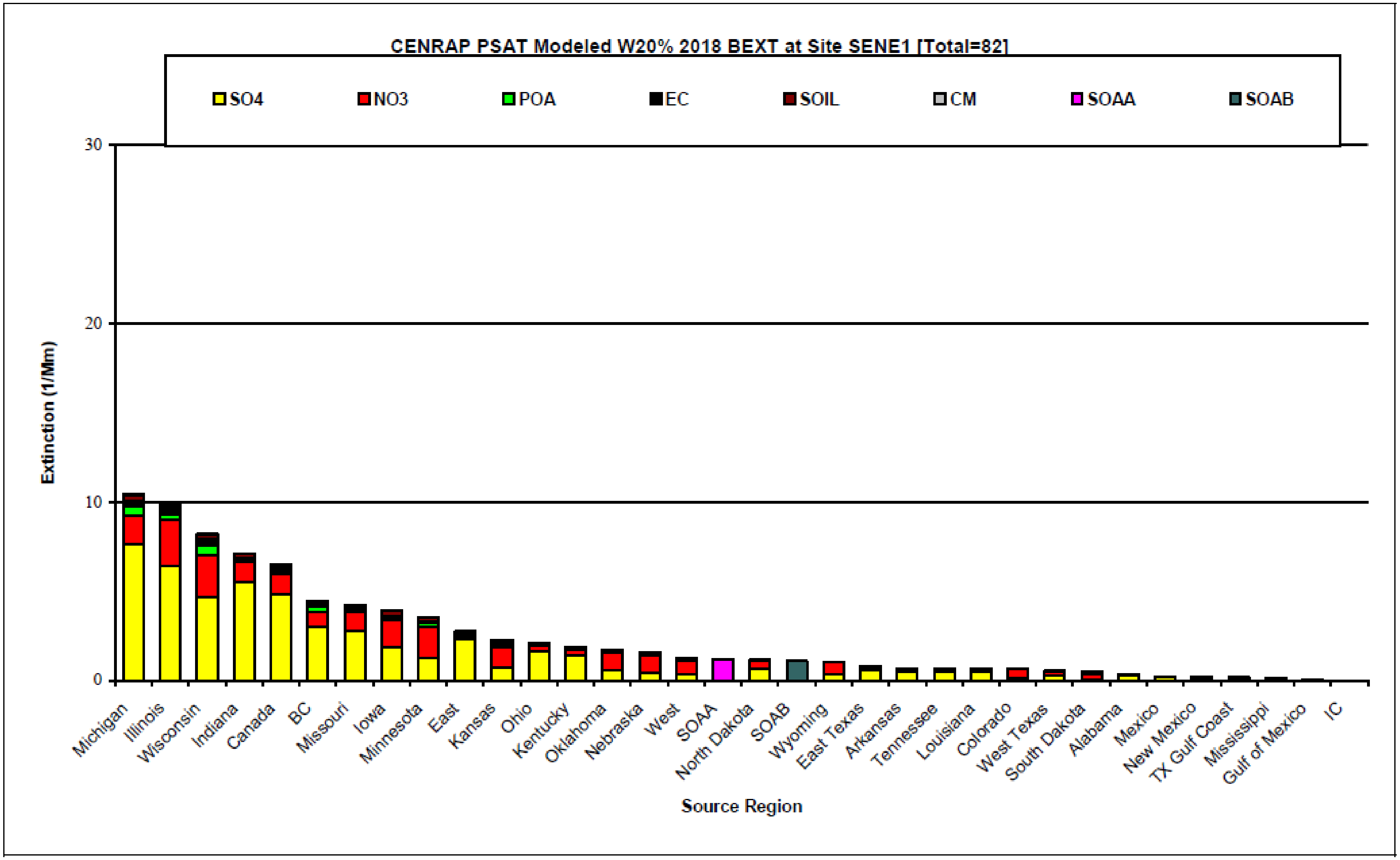


Figure 11.4. Source apportion contributions by region and pollutant to SENE in 2018.

Figure 12 PSAT Results from CENRAP CAMx Modeling for Boundary Waters Canoe Area Wilderness

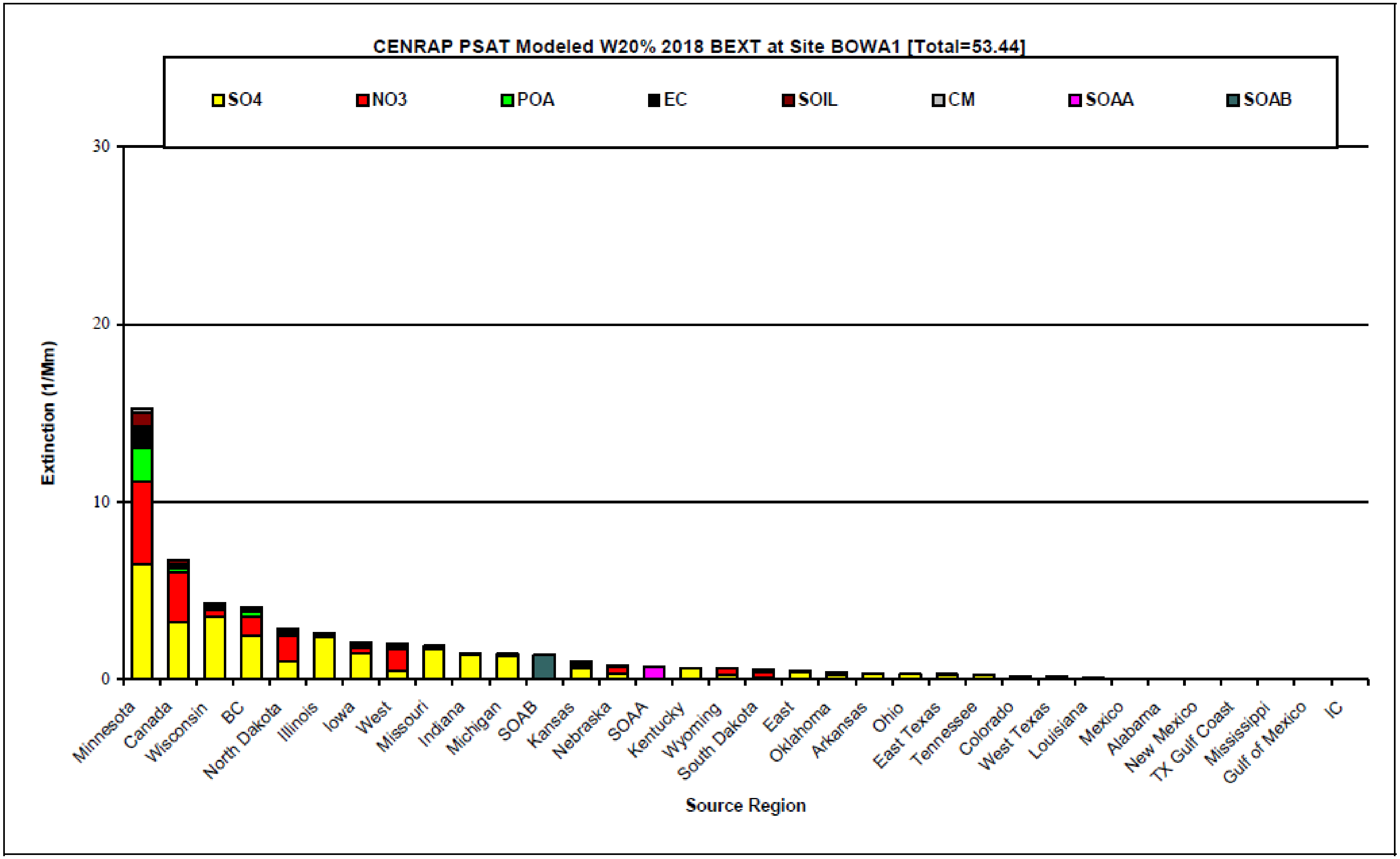


Figure 11.1. Source apportion contributions by region and pollutant to BOWA in 2018.

Figure 13 PSAT Results from CENRAP CAMx Modeling for Voyageurs National Park

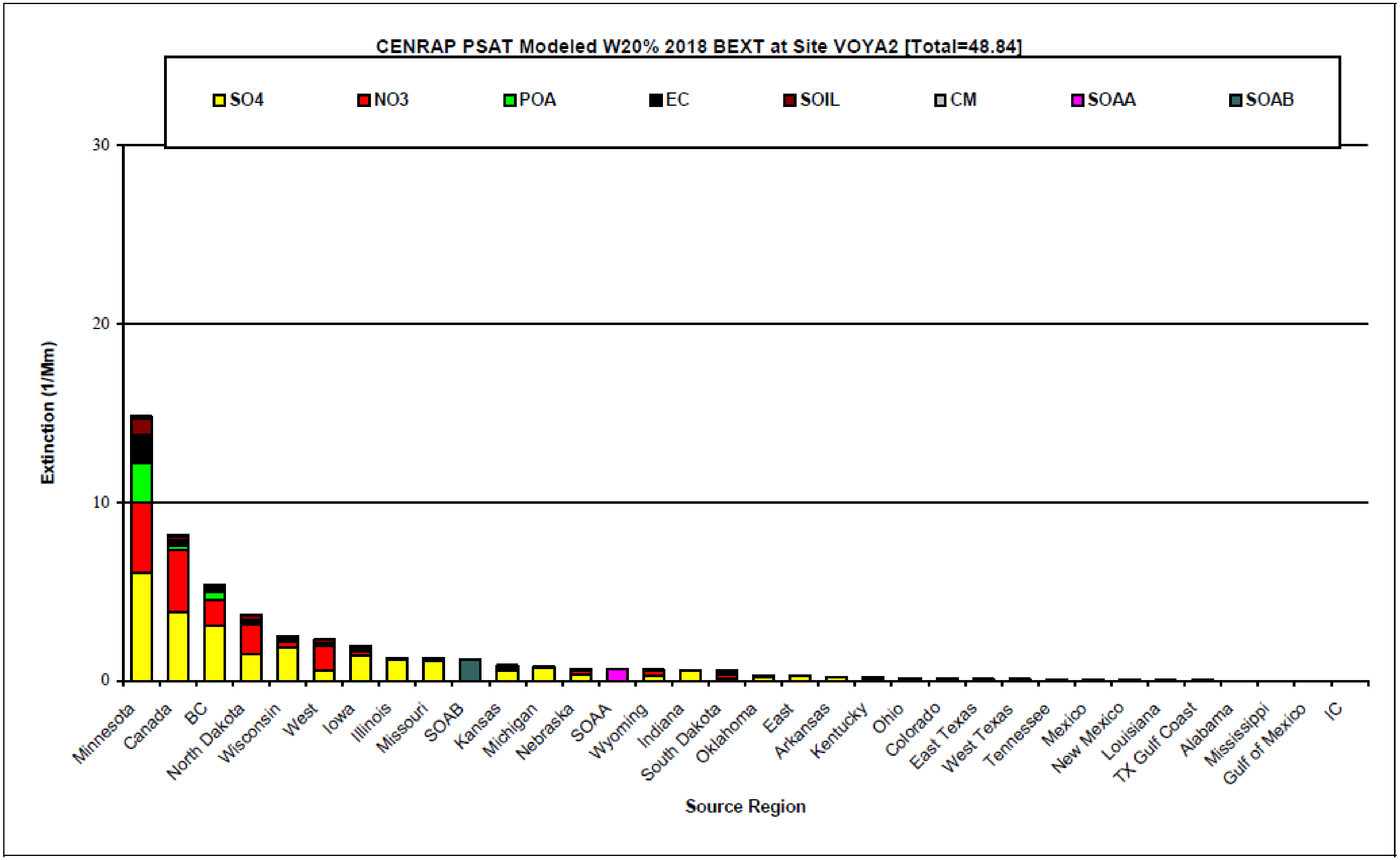


Figure 11.2. Source apportion contributions by region and pollutant to VOYA in 2018.

CONCLUSIONS

EPA's preferred modeling tools to assess the visibility improvement from BART controls will likely overestimate the predicted visibility improvement. While this is expected for all pollutants, it is especially true for NO_X emission controls. This occurs for several reasons:

- Natural background conditions, which are used in the calculation of haze impacts due to anthropogenic emissions, are mischaracterized as too clear, which exaggerates the impact of emission sources. Overly clean natural conditions can lead to the erroneous conclusion that some states are not adhering to the 2018 milestone because they need to achieve progress toward an impossible goal by the year 2064.

- The chemistry in the current EPA-approved version of CALPUFF as well as regional photochemical models overestimates winter nitrate haze, especially with the use of high ammonia background concentrations. There are other CALPUFF features that result in overpredictions of all pollutant concentrations. Therefore, BART emission reductions will be credited with visibility modeling for more visibility improvements than will really occur. We recommend that EPA adopt CALPUFF v. 6.42, which includes substantial improvements in the chemistry formulation. We also recommend the use of seasonally varying ammonia background concentrations, in line with observations and the current capabilities of CALPUFF.

- In addition to CALPUFF, the use of regional photochemical models results in significant nitrate haze overpredictions for Minnesota Class I area predictions.

- The modeled base case scenario is always a worst-case emission rate, assumed to occur every day. The actual emissions are often lower, and so the modeled improvement is an overestimate.

Impacts of the taconite plants' NO_X emissions are confined to winter months by the unique chemistry for nitrate particle formation. During these months, the attendance at the parks is greatly reduced by the closure of significant portions of the parks and the inability to conduct boating activities on frozen water bodies. In the case of Isle Royale National Park, there is total closure in the winter, lasting for 5 ½ months. The BART rule makes a provision for the consideration of such seasonal impacts. The imposition of NO_X controls year-round would not only have minimal benefits in the peak visitation season of summer, but also could lead to visibility disbenefits due to the increased power requirements (and associated emissions) needed for their operation, an effect that has not been considered in the visibility modeling.

Evidence of models' tendency for overprediction are provided in examples of actual significant emission reductions that have resulted in virtually no perceptive changes in haze, while visibility assessment modeling as conducted for BART would predict significant visibility improvements. These examples include the shutdown of the Mohave Generating Station (and minimal visibility effects at the Grand Canyon) as well as the economic slowdown that affected emissions from the taconite plants in 2009.

An analysis of the impact of the visibility impacts of Minnesota BART sources on Michigan's Class I areas, and vice versa indicates that the effects on the other state's Class I areas is minor. The taconite plant emissions are not expected to interfere with the ability of other states to achieve their required progress under the Regional Haze Rule.

APPENDIX A

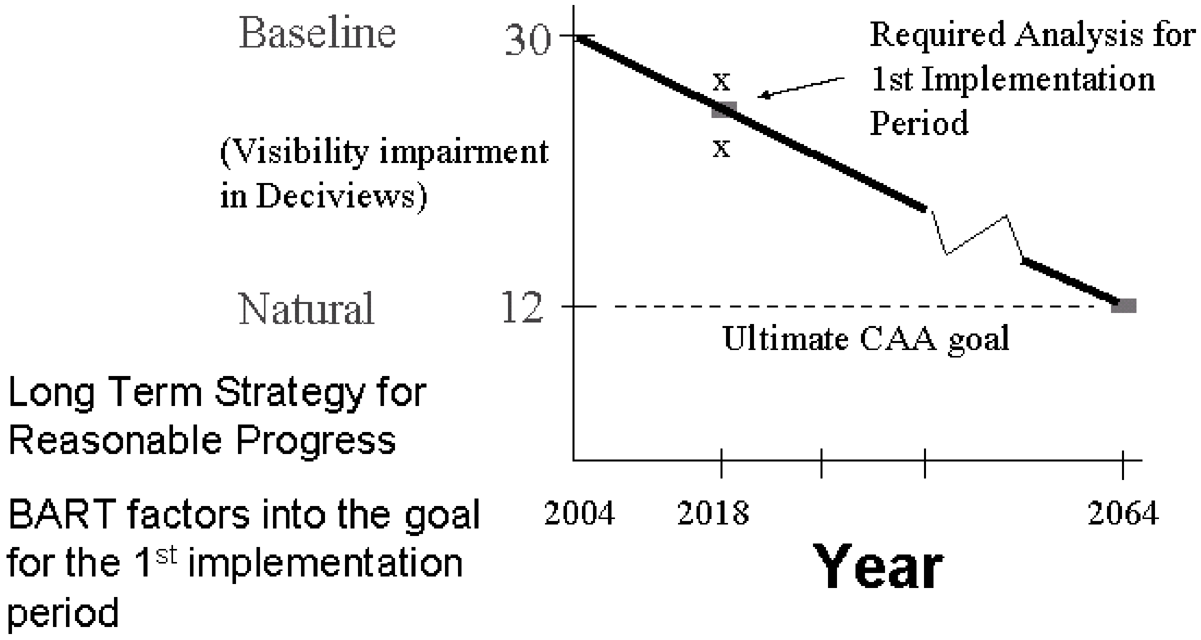
THE REGIONAL HAZE RULE GOAL OF NATURAL CONDITIONS

An important consideration in the ability for a state to meet the 2018 Uniform Rate of Progress (URP) goal is the definition of the end point goal of “natural conditions” for the worst 20% haze days; see Figure A-1, which illustrates this concept). Note that while achieving improved visibility for the worst 20% haze days, the RHR also stipulates that there should not be deterioration of visibility for the best 20%, or clearest, days. One way to define that goal would be the elimination of all man-made emissions. This raises some other questions, such as:

- To what categories of emissions does the RHR pertain?
- Does the current definition of natural conditions include non-anthropogenic or uncontrollable emissions?

The default natural background assumed by EPA in their 2003 guidance document[13] is not realistic. The discussion in this section explains why EPA’s default natural conditions significantly understate the true level of natural haze, including the fact that there are contributors of haze that are not controllable (and that are natural) that should be included in the definition of natural visibility conditions. In addition, one important aspect of the uncontrollable haze, wildfires, is further discussed regarding the biased quantification of its contribution to natural haze due to suppression of wildfires during the 20th century.

Figure A-1: Illustration of the Uniform Rate of Progress Goal



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[13] *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule*, (U.S. Environmental Protection Agency, September 2003). http://www.epa.gov/ttncaaa1/t1/memoranda/rh_envcurhr_gd.pdf.

In its RHR SIP, North Dakota[14] noted in Section 9.7 that,

"Achieving natural conditions will require the elimination of all anthropogenic sources of emissions. Given current technology, achieving natural conditions is an impossibility. Any estimate of the number of years necessary to achieve natural visibility conditions would require assumptions about future energy sources, technology improvements for sources of emissions, and every facet of human behavior that causes visibility impairing emissions. The elimination of all SO_2 and NO_x emissions in North Dakota will not achieve the uniform rate of progress for this [2018], or any future planning period. Any estimate of the number of years to achieve natural conditions is questionable because of the influence of out-of-state sources."

It will be extremely difficult, if not impossible, to eliminate all anthropogenic emissions, even if natural conditions are accurately defined. It will be even more daunting to try to reach the goal if natural conditions are significantly understated, and as a result, states are asked to control sources that are simply not controllable. It is clear that the use of EPA default natural conditions leads to unworkable and absurd results for one state's (North Dakota's) ability to determine the rate of progress toward an unattainable goal. The definition of natural conditions that can be reasonably attained for a reasonable application of USEPA's Regional Haze Rule should be revised for all states.

The objective of the following discussion is to summarize recent modeling studies of natural visibility conditions and to suggest how such studies can be used in evaluating the uniform rate of progress in reducing haze to attain natural visibility levels. In addition, the distinction between natural visibility and policy relevant background visibility is discussed. Treatment of this issue by other states, such as Texas, is also discussed.

Regional Haze Issues for Border States

There are similarities between the Regional Haze Rule (RHR) challenges for border states such as North Dakota and Texas in that both states have significant international and natural contributions to regional haze in Class I areas in their states. The Texas Commission on Environmental Quality (TCEQ) has introduced alternative RHR glide paths to illustrate the State's rate of progress toward the RHR goals. Since TCEQ has gone through the process of a RHR State Implementation Plan (SIP) development and comment period, it is instructive to look at the TCEQ approach, the comments provided by the Federal Land Managers to TCEQ, and TCEQ's reaction to the comments.

Similarities to be considered for the RHR SIP development in border states, such as North Dakota and Texas, include the items listed below.

- These states have Class I areas for which a considerable fraction of the regional haze is due to international transport or transport from other regions of the United States.

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[14] North Dakota Dep. of Health, 2010. North Dakota State Implementation Plan for Regional Haze. http://www.ndhealth.gov/AQ/RegionalHaze/Regional%20Haze%20Link%20Documents/Main%20SIP%20Sections%201-12.pdf.
.

- As a result, there is a substantial reduction in SO_2 and NO_x emissions from the BART-eligible sources in each state, but this reduction results in a relatively small impact on regional haze mitigation. Additional emission reductions would, therefore, have a minimal benefit on visibility improvement at substantial cost.

- In the Regional Haze SIP development, these states have attempted to account for the effects of anthropogenic emissions that they can control in alternative analyses. These analysis result in a finding that the in-state emission reductions come closer to meeting the Uniform Rate of Progress glide path goals for 2018. However, due to the low probability of impact of these sources on the worst 20% days, the effectiveness of in-state emission controls on anthropogenic sources subject to controls is inherently limited.

TCEQ decided that coarse and fine PM measured at the Class I areas were due to natural causes (especially on the worst 20% days), and adjusted the natural conditions endpoint accordingly. The Federal Land Managers (FLMs) agreed with this approach for the most part[15], but suggested that 80% of these concentrations would be due to natural causes, and 20% would be due to anthropogenic causes. TCEQ determined from a sensitivity analysis that the difference in these two approaches was too small to warrant a re-run of their analysis, but it is important that the FLMs agreed to a state-specific modification of the natural conditions endpoint, and this substantially changed the perceived rate of progress of the SIP plan toward the altered natural conditions endpoint.

Although the TCEQ did not address other particulate matter components in this same way, a review of air parcel back trajectories previously available from the IMPROVE web site (http://views.cira.colostate.edu/web/) suggests that other components, such as organic matter due to wildfires, could be substantially due to natural causes, so that this component should also be considered as at least partially natural.

The TCEQ discussed the issue of how emissions from Mexico could interfere with progress on the RHR, but they did not appear to adjust the glide path based upon Mexican emissions. On the other hand, in its weight of evidence analysis, North Dakota did evaluate adjustments based upon anthropogenic emissions that could not be controlled from Canadian sources, but did not take into account any specific particulate species that are generally not emitted by major anthropogenic sources of SO_2 and NO_X.

Natural Haze Levels

The Regional Haze Rule establishes the goal that natural visibility conditions should be attained in Federal Class I areas by the year 2064. Additionally, the states are required to determine the uniform rate of progress (URP) of visibility improvement necessary to attain the natural visibility goal by 2064. Finally, each state must develop a SIP identifying reasonable control measures that will be adopted well before 2018 to reduce source emissions of visibility-impairing particulate matter (PM) and its precursors (SO_2 and NO_x).

Estimates of natural haze levels have been developed by the EPA for visibility planning purposes and are described in the above-referenced EPA 2003 document. The natural haze estimates were based on ambient data analysis of selected PM species for days with good visibility and are shown in Table A-1.

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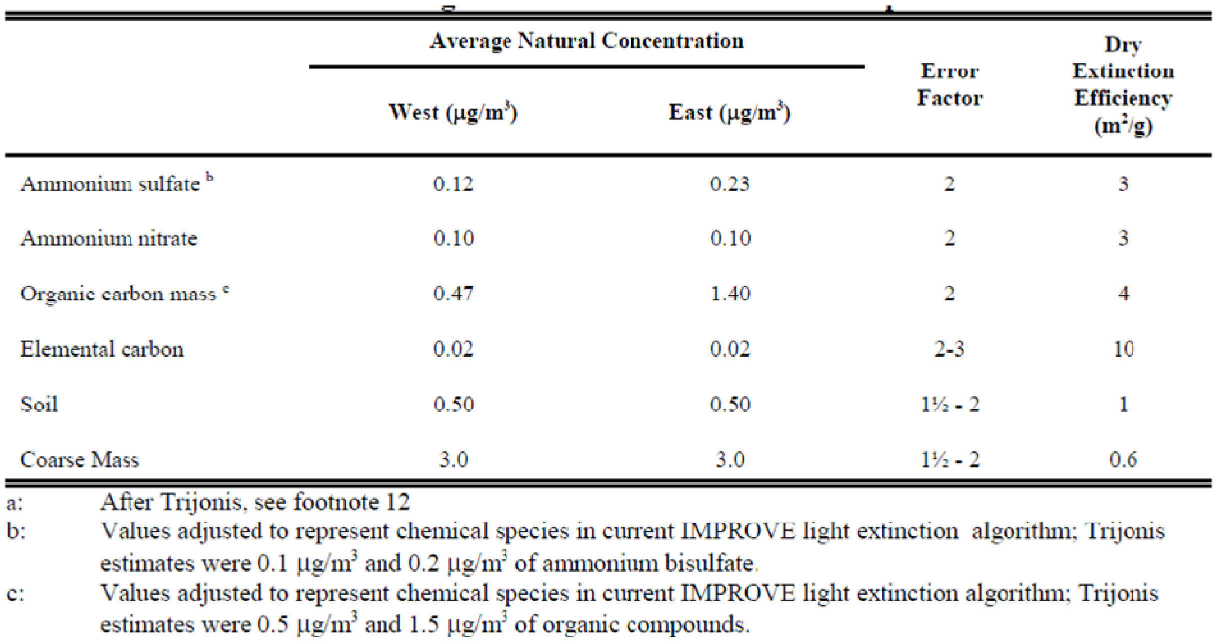
[15] See Appendix 2-2 at http://www.tceq.state.tx.us/implementation/air/sip/bart/haze_appendices.html.

These estimates were derived from Trijonis[16] and use two different sets of natural concentrations for the eastern and western U.S. Tombach[17] provides a detailed review and discussion of uncertainty in the USEPA natural PM estimates. Natural visibility can be calculated using the IMPROVE equation which calculates the light scattering caused by each component of PM. After much study, changes in the IMPROVE equation and in the method for calculating natural visibility were developed in 2005 and are described by Pitchford et al.[18]

Table A-1: Average Natural Levels of Aerosol Components from Table 2-1 of *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule* (EPA, 2003)



	Average Natural Concentration		Error Factor	Dry Extinction Efficiency (m^2/g)
	West ($\mu g/m^3$)	East ($\mu g/m^3$)		
Ammonium sulfate [b]	0.12	0.23	2	3
Ammonium nitrate	0.10	0.10	2	3
Organic carbon mass [c]	0.47	1.40	2	4
Elemental carbon	0.02	0.02	2-3	10
Soil	0.50	0.50	1½ - 2	1
Coarse Mass	3.0	3.0	1½ - 2	0.6

a: After Trijonis, see footnote 12

b: Values adjusted to represent chemical species in current IMPROVE light extinction algorithm; Trijonis estimates were 0.1 $\mu g/m^3$ and 0.2 $\mu g/m^3$ of ammonium bisulfate.

c: Values adjusted to represent chemical species in current IMPROVE light extinction algorithm; Trijonis estimates were 0.5 $\mu g/m^3$ and 1.5 $\mu g/m^3$ of organic compounds.

The EPA guidance also makes provision for refined estimates of site-specific natural haze that differ from the default values using either data analysis or model simulations. However, most states have continued to use the default natural haze levels for calculating the progress toward natural visibility conditions.

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[16] Trijonis, J. C. Characterization of Natural Background Aerosol Concentrations. Appendix A in Acidic Deposition: State of Science and Technology. Report 24. Visibility: Existing and Historical Conditions -- Causes and Effects. J. C. Trijonis, lead author. National Acid Precipitation Assessment Program: Washington, DC, 1990.

[17] Tombach, I., (2008) *Natural Haze Levels Sensitivity -- Assessment of Refinements to Estimates of Natural Conditions,* Report to the Western Governors Association, January 2008, available at http://www.wrapair.org/forums/aamrf/projects/NCB/index.html.

[18] Pitchford, M., Malm, W., Schichtel, B., Kumar, N., Lowenthal, D., Hand, J., Revised Algorithm for Estimating Light Extinction from IMPROVE Particle Speciation Data, J. Air & Waste Manage, Assoc. 57: 1326 – 1336, 2007.

Tombach and Brewer[19] reviewed natural sources of PM and identified several Class I areas for which evidence supports adjustments to the natural levels. Tombach[8] also reviewed estimates of natural haze levels and proposed that, instead of using two sets of default natural PM concentrations for the eastern and western US, a large number of sensitivity zones should be developed that reflect regional variability in natural PM sources. Tombach[8] also suggested that modeling studies are a possible approach to further revise estimates of natural PM concentrations.

Previous modeling studies have shown that the estimates of natural visibility described above for “clean” days will differ from the results of model simulations when United States anthropogenic emissions are totally eliminated (Tonnesen et al., 2006[20]; Koo et al., 2010[21]), especially when natural wild fire emissions are included in the model simulation. Because the URP is calculated using model simulations of PM on the 20% of days with the worst visibility, wild fires and other extreme events can result in estimated levels of natural haze (even without any contribution of US anthropogenic sources) that can be significantly greater than the natural levels used in the EPA guidance for URP calculation. This could make it difficult or impossible for states to identify emissions control measures sufficient to demonstrate the URP toward attaining visibility goals because the endpoint is unachievable even if all US anthropogenic emissions are eliminated, as North Dakota has already determined even for the interim goal in 2018.

Previous Suppression of Wildfire Activity and its Effect upon the EPA Default Natural Conditions

Throughout history, except for the past few decades, fires have been used to clear land, change plant and tree species, sterilize land, maintain certain types of habitat, among other purposes. Native Americans used fires as a technique to maintain certain pieces of land or to improve habitats. Although early settlers often used fires in the same way as the Native Americans, major wildfires on public domain land were largely ignored and were often viewed as an opportunity to open forestland for grazing.

Especially large fires raged in North America during the 1800s and early 1900s. The public was becoming slowly aware of fire's potential for life-threatening danger. Federal involvement in trying to control forest fires began in the late 1890s with the hiring of General Land Office rangers during the fire season. When the management of the forest reserves (now called national forests) was transferred to the newly formed Forest Service in 1905, the agency took on the responsibility of creating professional standards for firefighting, including having more rangers and hiring local people to help put out fires.

Since the beginning of the 20th century, fire suppression has resulted in a buildup of vegetative “fuels” and catastrophic wildfires. Recent estimates of background visual range, such as Trijonis[16], have underestimated the role of managed fire on regional haze. Since about 1990, various government agencies have increased prescribed burning to reduce the threat of dangerous wildfires, and the

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[19] Tombach, I., and Brewer, P. (2005). Natural Background Visibility and Regional Haze Goals in the Southeastern United States. *J. Air & Waste Manage. Assoc. 55*, 1600-1620.

[20] Tonnesen, G., Omary, M., Wang, Z., Jung, C.J., Morris, R., Mansell, G., Jia, Y., Wang, B., and Z. Adelman (2006) Report for the Western Regional Air Partnership Regional Modeling Center, University of California Riverside, Riverside, California, November. (http://pah.cert.ucr.edu/aqm/308/reports/final/2006/WRAP-RMC_2006_report_FINAL.pdf).

[21] Koo B., C.J. Chien, G. Tonnesen, R. Morris , J. Johnson, T. Sakulyanontvittaya, P. Piyachaturawat, and G.Yarwood, 2010. Natural emissions for regional modeling of background ozone and particulate matter and impacts on emissions control strategies. Atm. Env., 44, 2372-2382.

increased haze due to these fires is often more of an impairment to visibility than industrial sources, especially for NO_X reductions that are only effective in winter, the time of the lowest tourist visitation in most cases.

The National Park Service indicates at http://www.nps.gov/thro/parkmgmt/firemanagement.htm for the Theodore Roosevelt National Park that:

"For most of the 20th Century, wildfires were extinguished immediately with the assumption that doing so would protect lives, property, and natural areas. However, following the unusually intense fire season of 1988, agencies including the National Park Service began to rethink their policies." Even this policy is not always successful, as experienced by the USDA Forest Service[22] in their management of wildfires near the Boundary Waters Canoe Area that can contribute significantly to visibility degradation during the peak tourist season. In this case, even small fires, if left unchecked, have been known to evolve into uncontrollable fires and then require substantial resources to extinguish.

EPA's 2003 "Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program" acknowledges that wildfires are a contributor to natural visibility conditions, but the data used in estimates of natural conditions were taken during a period of artificial fire suppression so that the true impact of natural wildfires is understated. The report notes that "data should be available for EPA and States to develop improved estimates of the contribution of fire emissions to natural visibility conditions in mandatory Federal Class I areas over time." As noted by several studies noted above, the impact due to natural fire levels is underestimated in the EPA natural visibility background estimates. The consequences of the artificially low estimates of natural visibility conditions include the distortion of Reasonable Progress analyses and also to BART modeling results that overestimate the visibility improvement achievable from NO_X emission reductions due to the use of inaccurate natural visibility conditions.

Recommendations for an Improved Estimate of Visibility Natural Conditions

A reasonable approach would be to combine the effects of the uncontrollable particulate matter components and the emissions from international sources to determine a new glide path endpoint that is achievable by controlling (only) U.S. anthropogenic emissions. To compute this new endpoint, regional photochemical modeling using CMAQ or CAMx could be conducted for the base case (already done) and then for a future endpoint case that has no U.S. anthropogenic emissions, but with natural particulate matter emissions (e.g., dust, fires, organic matter) as well as fine particulate, SO_2 and NO_x emissions associated with all non-U.S. sources set to the current baseline levels. The simulation should include an higher level of wildfire activity than in the recent past to reflect a truer level of fire activity before manmade suppression in the 20th century. Then, states could use a relative reduction factor (RRF) approach to determine the ratio of the haze impacts between the base case and the reasonable future case, and then apply the RRF values to the baseline haze to obtain a much more reasonable "natural conditions" haze endpoint. The more accurate natural background would also result in a reduction in the degree to which CALPUFF modeling overstates visibility improvement from emission reductions.

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[22] See explanation at http://www.msnbc.msn.com/id/48569985/ns/us_news-environment/t/forest-service-gets-more-aggressive-small-fires/.

APPENDIX B

MODEL OVERPREDICTION ISSUES FOR WINTERTIME NITRATE HAZE

This appendix includes a discussion of CALPUFF predictions for nitrate haze, followed by more general issues with CALPUFF predictions.

CALPUFF Predictions of Nitrate Haze

Secondary pollutants such as nitrates and sulfates contribute to light extinction in Class I areas. The CALPUFF model was approved by EPA for use in BART determinations to evaluate the effect of these pollutants on visibility in Class I areas. CALPUFF version 5.8 (the current guideline version) uses the EPA-approved MESOPUFF II chemical reaction mechanism to convert SO_2 and NO_X emissions to secondary sulfate and nitrate. This section describes how secondary pollutants, specifically nitrate, are formed and the factors affecting their formation, especially as formulated in CALPUFF.

In the CALPUFF model, the oxidation of NO_X to nitric acid (HNO_3) depends on the NO_X concentration, ambient ozone concentration, and atmospheric stability. Some of the nitric acid is then combined with available ammonia in the atmosphere to form ammonium nitrate aerosol in an equilibrium state that is a function of temperature, relative humidity, and ambient ammonia concentration. In CALPUFF, total nitrate ($TNO_3 = HNO_3 + NO_3$) is partitioned into gaseous HNO_3 and NO_3 particles according to the equilibrium relationship between the two species. This equilibrium is a function of ambient temperature and relative humidity. Moreover, the formation of nitrate particles *strongly* depends on availability of NH_3 to form ammonium nitrate, as shown in Figure 6[23]. The figure on the left shows that with 1 ppb of available ammonia and fixed temperature and humidity (for example, 275 K and 80% humidity), only 50% of the total nitrate is in the form of particulate matter. When the available ammonia is increased to 2 ppb, as shown in the figure on the right, as much as 80% of the total nitrate is in the particulate form. Figure B-1 also shows that colder temperatures and higher relative humidity favor particulate nitrate formation. A summary of the conditions affecting nitrate formation are listed below:

- Colder temperature and higher relative humidity create more favorable conditions to form nitrate particulate matter in the form of ammonium nitrate;
- Warmer temperatures and lower relative humidity create less favorable conditions for nitrate particulate matter resulting in a small fraction of total nitrate in the form of ammonium nitrate;
- Ammonium sulfate formation preferentially scavenges available atmospheric ammonia over ammonium nitrate formation. In air parcels where sulfate concentrations are high and ambient ammonia concentrations are low, there is less ammonia available to react with nitrate, and less ammonium nitrate is formed.

The effects of temperature and background ammonia concentrations on the nitrate formation are the key to understanding the effects of various NO_X control options. For the reasons discussed above, the seasons with lower temperatures are the most likely to be most important for ammonium nitrate formation when regional haze is more effectively reduced by controlling NO_X.

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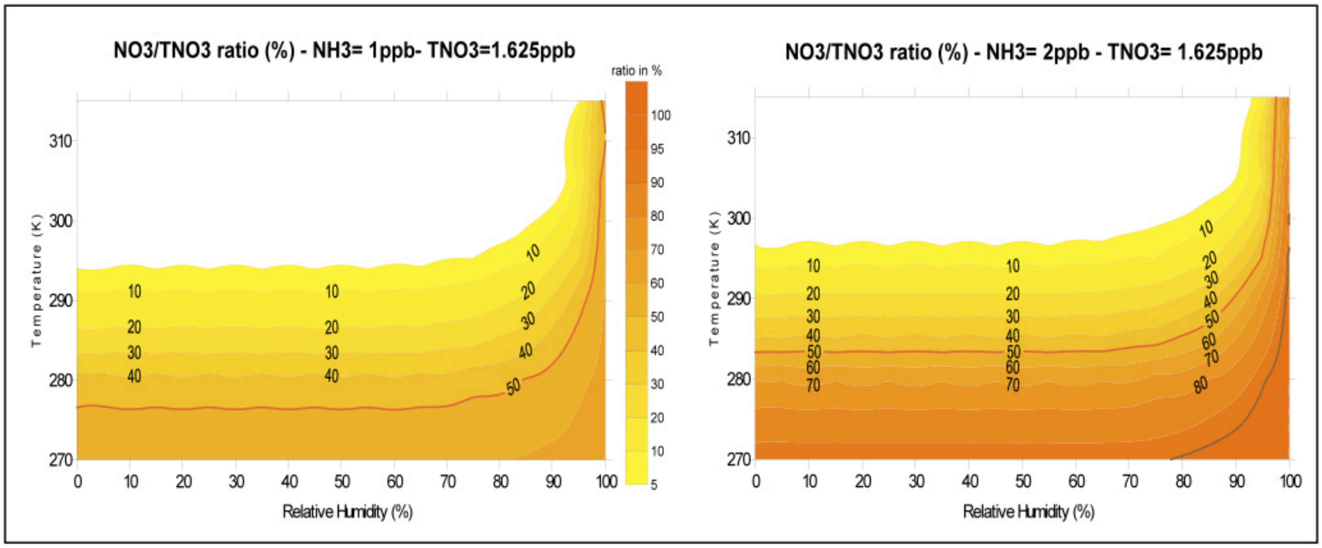
[23] Scire, Joseph. CALPUFF MODELING SYSTEM. CALPUFF course presented at Chulalongkorn University, Bangkok, Thailand. May 16-20, 2005; slide 40 available at http://aqnis.pcd.go.th/tapce/plan/4CALPUFF%20slides.pdf, accessed March 2011.

Figure B-1: NO_3/HNO_3 Equilibrium Dependency on Temperature and Humidity



Sensitivity of CALPUFF Haze Calculations to Background Ammonia Concentration

In an independent analysis, the Colorado Department of Public Health and Environment (CDPHE) performed a sensitivity modeling analysis to explore the effect of the specified ammonia concentration applied in CALPUFF on the predicted visibility impacts for a source with high NO_X emissions relative to SO_2 emissions[24]. The results of the sensitivity modeling are shown in Figure B-2. It is noteworthy that the largest sensitivity occurs for specified ammonia input between 1 and 0.1 ppb. In that factor-of-ten range, the difference in the peak visibility impact predicted by CALPUFF is slightly more than a factor of three. This sensitivity analysis shows that the specification of background ammonia is very important in terms of the magnitude of visibility impacts predicted by CALPUFF. The fact that regional, diurnal and seasonal variations of ambient ammonia concentrations are not well-characterized and mechanisms not well-understood effectively limits the effectiveness of CALPUFF in modeling regional haze, especially in terms of the contribution of ammonium nitrate.

It is also noteworthy that CALPUFF version 5.8's demonstrated over-predictions of wintertime nitrate can be mitigated to some extent by using lower winter ammonia background values, although there is not extensive measurement data to determine the ambient ammonia concentrations. This outcome showing the superiority of the monthly-varying background ammonia concentrations was found by Salt River

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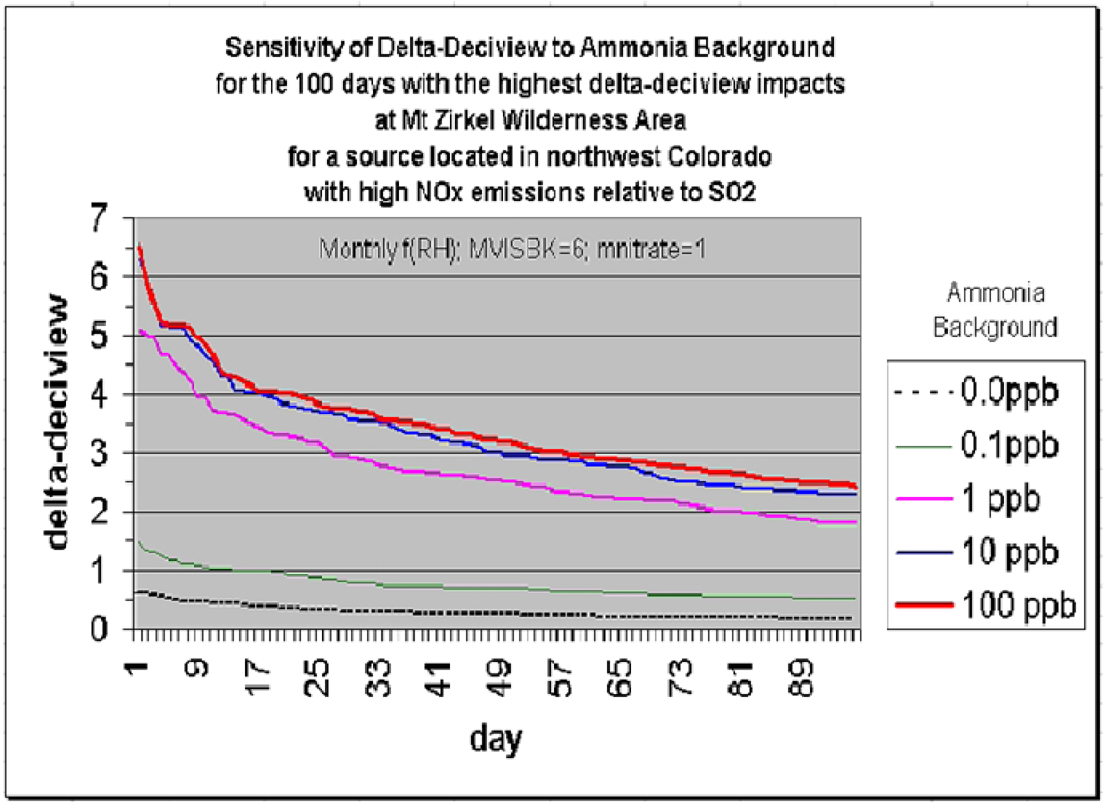
[24] Supplemental BART Analysis: CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis (DRAFT), revised June 25, 2010, available at http://www.colorado.gov/airquality/documents/Draft-ColoradoSupplementalBARTAnalysisCALPUFFProtocol-25June2010.pdf. (2010)

Project in case studies of the Navajo Generating Station impacts on Grand Canyon monitors, as presented[25] to EPA in 2010.

It is important to note that 14 years ago in 1998, when the IWAQM Phase 2 guidance[26] was issued, CALPUFF did not even have the capability of accommodating monthly ammonia background concentrations; only a single value was allowed. Since then, CALPUFF has evolved to be able to receive as input monthly varying ammonia concentrations. EPA's guidance on the recommended input values that are constant all year has not kept pace with the CALPUFF's capability. The weight of evidence clearly indicates that the use of monthly varying ammonia concentrations with lower wintertime values will result in more accurate predictions.

Figure B-2: CDPHE Plot of Sensitivity of Visibility Impacts Modeled by CALPUFF for Different Ammonia Backgrounds.



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[25] Salt River Project, 2010. Measurements of Ambient Background Ammonia on the Colorado Plateau and Visibility Modeling Implications. Salt River Project, P.O. Box 52025 PAB352, Phoenix, Arizona 85072.

[26] IWAQM Phase 2 Summary Report and Recommendations (EPA-454/R-98-019), EPA OAQPS, December 1998). http://www.epa.gov/scram001/7thconf/calpuff/phase2.pdf.

Independent Studies of the Effect of Model Chemistry on Nitrate Predictions

The Regional Haze BART Rule acknowledged that CALPUFF tends to overestimate the amount of nitrate that is produced. In particular, the overestimate of ammonium nitrate concentrations on visibility at Class I areas is the greatest in the winter, when temperatures (and visitation) are lowest, the nitrate concentrations are the greatest, and the sulfate concentrations tend to be the least due to reduced oxidation rates of SO_2 to sulfate.

On page 39121, the BART rule[27] stated that: "…the simplified chemistry in the [CALPUFF] model tends to magnify the actual visibility effects of that source."

On page 39123, the BART rule stated that: "We understand the concerns of commenters that the chemistry modules of the CALPUFF model are less advanced than some of the more recent atmospheric chemistry simulations. In its next review of the Guideline on Air Quality Models, EPA will evaluate these and other newer approaches[28]."

EPA did not conduct such an evaluation, but the discussion below reports on the efforts of other investigators.

A review of independent evaluations of the CALPUFF model is reported here, with a focus on identifying studies that address the nitrate chemistry used in the model. Morris et al.[29] reported that the CALPUFF MESOPUFF II transformation rates were developed using temperatures of 86, 68 and 50°F. Therefore, the 50°F minimum temperature used in development of the model could result in overestimating sulfate and nitrate formation in colder conditions. These investigators found that CALPUFF tended to overpredict nitrate concentrations during winter by a factor of about three.

A recent independent study of the CALPUFF performance by Karamchandani et al (referred to here as the KCBB study) is highly relevant to this issue[30]. The KCBB study presented several improvements to the Regional Impacts on Visibility and Acid Deposition (RIVAD) chemistry option in CALPUFF, an alternative treatment that was more amenable to an upgrade than the MESOPUFF II chemistry option. Among other items, the improvements included the replacement of the original CALPUFF secondary particulate matter (PM) modules by newer algorithms that are used in current state-of-the-art regional air quality models such as CMAQ, CMAQ-MADRID, CAMx and REMSAD, and in advanced puff models

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[27] July 6, 2005 Federal Register publication of the Regional Haze BART rule.

[28] The next (9th) EPA modeling conference was held in 2008, during which the concepts underlying the chemistry upgrades in CALPUFF 6.42 were presented. However, EPA failed to conduct the promised evaluation in its review of techniques at that conference held 4 years ago. As a result of the 10th EPA modeling conference held in March 2012, EPA appears to be continuing to rely upon CALPUFF version 5.8, which it admitted in the July 6, 2005 BART rule has serious shortcomings.

[29] Morris, R., Steven Lau and Bonyoung Koo. Evaluation of the CALPUFF Chemistry Algorithms. Presented at A&WMA 98th Annual Conference and Exhibition, June 21-25, 2005 Minneapolis, Minnesota. (2005)

[30] Karamchandani, P., S. Chen, R. Bronson, and D. Blewitt. Development of an Improved Chemistry Version of CALPUFF and Evaluation Using the 1995 SWWYTAF Data Base. Presented at the Air & Waste Management Association Specialty Conference on Guideline on Air Quality Models: Next Generation of Models, October 28-30, 2009, Raleigh, NC. (2009)

such as SCICHEM. In addition, the improvements included the incorporation of an aqueous-phase chemistry module based on the treatment in CMAQ. Excerpts from the study papers describing each of the improvements made to CALPUFF in the KCBB study are repeated below.

Gas-Phase Chemistry Improvements

The KCBB study applied a correction to CALPUFF in that the upgraded model was modified to keep track of the puff ozone concentrations between time steps. The authors also updated the oxidation rates of SO_2 and nitrogen dioxide (NO_2) by the hydroxide ion (OH^-) to the rates employed in contemporary photochemical and regional PM models.

Treatment of Inorganic Particulate Matter

The KCBB study scientists noted that the EPA-approved version of CALPUFF currently uses a simple approach to simulate the partitioning of nitrate and sulfate between the gas and particulate phases. In this approach, sulfate is appropriately assumed to be entirely present in the particulate phase, while nitrate is assumed to be formed by the reaction between nitric acid and ammonia.

The KCBB study implemented an additional treatment for inorganic gas-particle equilibrium, based upon an advanced aerosol thermodynamic model referred to as the ISORROPIA model[31]. This model is currently used in several state-of-the-art regional air quality models. With this new module, the improved CALPUFF model developed in the KCBB study includes a treatment of inorganic PM formation that is consistent with the state of the science in air quality modeling, and is critical for the prediction of regional haze due to secondary nitrate formation from NO_X emissions.

Treatment of Organic Particulate Matter

The KCBB study added a treatment for secondary organic aerosols (SOA) that is coupled with the corrected RIVAD scheme described above. The treatment is based on the Model of Aerosol Dynamics, Reaction, Ionization and Dissolution (MADRID)[32,33], which treats SOA formation from both anthropogenic and biogenic volatile organic compound emissions.

Aqueous-Phase Chemistry

The current aqueous-phase formation of sulfate in both CALPUFF's RIVAD and MESOPUFF II schemes is currently approximated with a simplistic treatment that uses an arbitrary pseudo-first order rate in the presence of clouds (0.2% per hour), which is added to the gas-phase rate. There is no explicit treatment

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[31] Nenes A., Pilinis C., and Pandis S.N. Continued Development and Testing of a New Thermodynamic Aerosol Module for Urban and Regional Air Quality Models, *Atmos. Env.* **1998**, 33, 1553-1560.

[32] Zhang, Y., B. Pun, K. Vijayaraghavan, S.-Y. Wu, C. Seigneur, S. Pandis, M. Jacobson, A. Nenes and J.H. Seinfeld. Development and Application of the Model of Aerosol Dynamics, Reaction, Ionization and Dissolution (MADRID), *J. Geophys. Res.* **2004**, 109, D01202, doi:10.1029/2003JD003501.

[33] Pun, B., C. Seigneur, J. Pankow, R. Griffin, and E. Knipping. An upgraded absorptive secondary organic aerosol partitioning module for three-dimensional air quality applications, 24th Annual American Association for Aerosol Research Conference, Austin, TX, October 17-21, 2005. (2005)

of aqueous-phase SO_2 oxidation chemistry. The KCBB study incorporated into CALPUFF a treatment of sulfate formation in clouds that is based on the treatment that is used in EPA's CMAQ model.

CALPUFF Model Evaluation and Sensitivity Tests

The EPA-approved version of CALPUFF and the version with the improved chemistry options were evaluated using the 1995 Southwest Wyoming Technical Air Forum (SWWYTAF) database[34], available from the Wyoming Department of Environmental Quality. The database includes MM5 output for 1995, CALMET and CALPUFF codes and control files, emissions for the Southwest Wyoming Regional modeling domain, and selected outputs from the CALPUFF simulations. Several sensitivity studies were also conducted to investigate the effect of background NH_3 concentrations on model predictions of PM nitrate. Twice-weekly background NH_3 concentrations were provided from monitoring station observations for the Pinedale, Wyoming area. These data were processed to calculate seasonally averaged background NH_3 concentrations for CALPUFF.

Two versions of CALPUFF with different chemistry modules were evaluated with this database:

1. MESOPUFF II chemistry using the Federal Land Managers' Air Quality Related Values Work Group (FLAG) recommended background NH_3 concentration of 1 ppb for arid land. As discussed previously, the MESOPUFF II algorithm is the basis for the currently approved version of CALPUFF that is being used for BART determinations throughout the United States.

2. Improved CALPUFF RIVAD/ARM3 chemistry using background values of NH_3 concentrations based on measurements in the Pinedale, Wyoming area, as described above.

PM sulfate and nitrate were predicted by the two models and compared with actual measured values obtained at the Bridger Wilderness Area site from the IMPROVE network and the Pinedale site from the Clean Air Status and Trends Network (CASTNET). For the two model configurations evaluated in this study, the results for PM sulfate were very similar, which was expected since the improvements to the CALPUFF chemistry were anticipated to have the most impact on PM nitrate predictions. Therefore, the remaining discussion focuses on the performance of each model with respect to PM nitrate.

The EPA-approved CALPUFF model was found to significantly overpredict PM nitrate concentrations at the two monitoring locations, by a factor of two to three. The performance of the version of CALPUFF with the improved RIVAD chemistry was much better, with an overprediction of about 4% at the Pinedale CASTNET site and of about 28% at the Bridger IMPROVE site.

In an important sensitivity analysis conducted within the KCBB study, both the EPA-approved version of CALPUFF and the improved version were run with a constant ammonia background of 1 ppb, as recommended by IWAQM Phase II[35]. The results were similar to those noted above: the improved

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[34] Wyoming Department of Environmental Quality. 1995 Southwest Wyoming Technical Air Forum (SWWYTAF) database. Background and database description are available at http://deq.state.wy.us/aqd/prop/2003AppF.pdf. (2010)

[35] Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Long-Range Transport Modeling, EPA-454/R-98-019. (1998)

CALPUFF predictions were about two to three times lower than those from the EPA-approved version of CALPUFF. This result is similar to the results using the seasonal observed values of ammonia, and indicates that the sensitivity of the improved CALPUFF model to the ammonia input value is potentially less than that of the current EPA-approved model.

Similar sensitivity was noted by Scire et al. in their original work in the SWWYATF study[36], in which they tested seasonally varying levels of background ammonia in CALPUFF (using 0.23 ppb in winter, for example; see Figure B-3. The sensitivity modeling for predicting levels of nitrate formation shows very similar results to those reported in the KCBB study.

These findings indicate that to compensate for the tendency of the current EPA-approved version of CALPUFF to overpredict nitrates, the background ammonia values that should be used as input in CALPUFF modeling should be representative of isolated areas (e.g., Class I areas).

On November 3, 2010, TRC released a new version (6.42) of CALPUFF to fix certain coding "bugs" in EPA-approved version 5.8 and to improve the chemistry module. Additional enhancements to CALPUFF version 6.42 have been reported at EPA's 10th modeling conference in March 2012 by Scire[37], who also has conducted recent evaluations of this version in comparison to the regulatory version (5.8). Despite the evidence that this CALPUFF version is a generation ahead of the currently approved version for modeling secondary particulate formation, EPA has not acted to adopt it as a guideline model. Even with evidence provided by independent investigators[29,30] that also indicate that wintertime nitrate estimated by CALPUFF version 5.8 is generally overpredicted by a factor between 2 and 4, EPA has not taken steps to adopt the improved CALPUFF model, noting that extensive peer review, evaluations, and rulemaking are still needed for this adoption to occur. In the meantime, EPA, in retaining CALPUFF version 5.8 as the regulatory model for regional haze predictions, is ignoring the gross degree of overestimation of particulate nitrate and is thus ensuring that regional haze modeling conducted for BART is overly conservative. EPA's delay in adopting CALPUFF version 6.42 will thus result in falsely attributing regional haze mitigation to NO_X emission reductions.

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[36] Scire, J.S., Z-X Wu, D.G. Strimaitis and G.E. Moore. The Southwest Wyoming Regional CALPUFF Air Quality Modeling Study – Volume I. Prepared for the Wyoming Dept of Environmental Quality. (2001)

[37] Scire, J., 2012. New Developments and Evaluations of the CALPUFF Model. http://www.epa.gov/ttn/scram/10thmodconf/presentations/3-5-CALPUFF_Improvements_Final.pdf.

OVERPREDICTIONS OF NITRATE HAZE BY REGIONAL PHOTOCHEMICAL MODELS

The overprediction tendency for modeling of wintertime nitrate haze is not limited to CALPUFF. Even the state-of-the-art regional photochemical models are challenged in getting the right ammonium nitrate concentrations. This is evident in a presentation[38] made by Environ to the CENRAP Regional Planning Organization in 2006. The relevant figures from the Ralph Morris presentation (shown in Figures B-4 and B-5 below) indicate that both CMAQ and CAMx significantly overpredict nitrate haze in winter at Voyageurs National Park, by about a factor of 2. This is shown by the height of the red portion of the composition plot stacked bars between the observed and predicted timelines. It is noteworthy that Minnesota and EPA have relied upon this modeling approach for their BART determinations. Similar to CALPUFF, as discussed above, the agency modeling is prone to significantly overpredicting wintertime nitrate haze, leading to an overestimate of visibility improvement with NO_X emission reductions.

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[38] http://pah.cert.ucr.edu/aqm/cenrap/meetings.shtml, under “MPE”, slides 9 and 10.

Figure B-3: Sensitivity Study of Nitrate Predictions at Bridger Wilderness Area for Input Ammonia Concentrations to CALPUFF (0.23, 0.5, and 1.0 ppb).

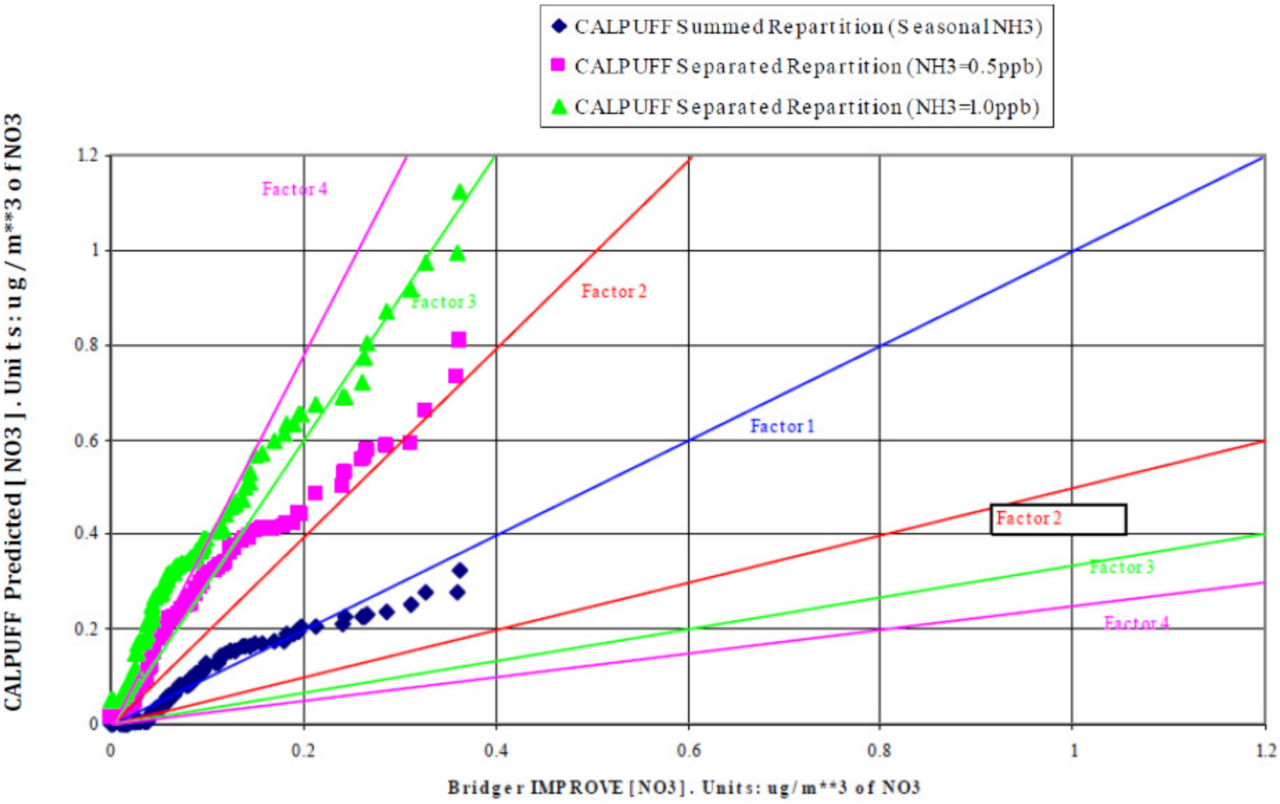


Figure B-4 CMAQ vs. Observed Haze Predictions at Voyageurs National Park

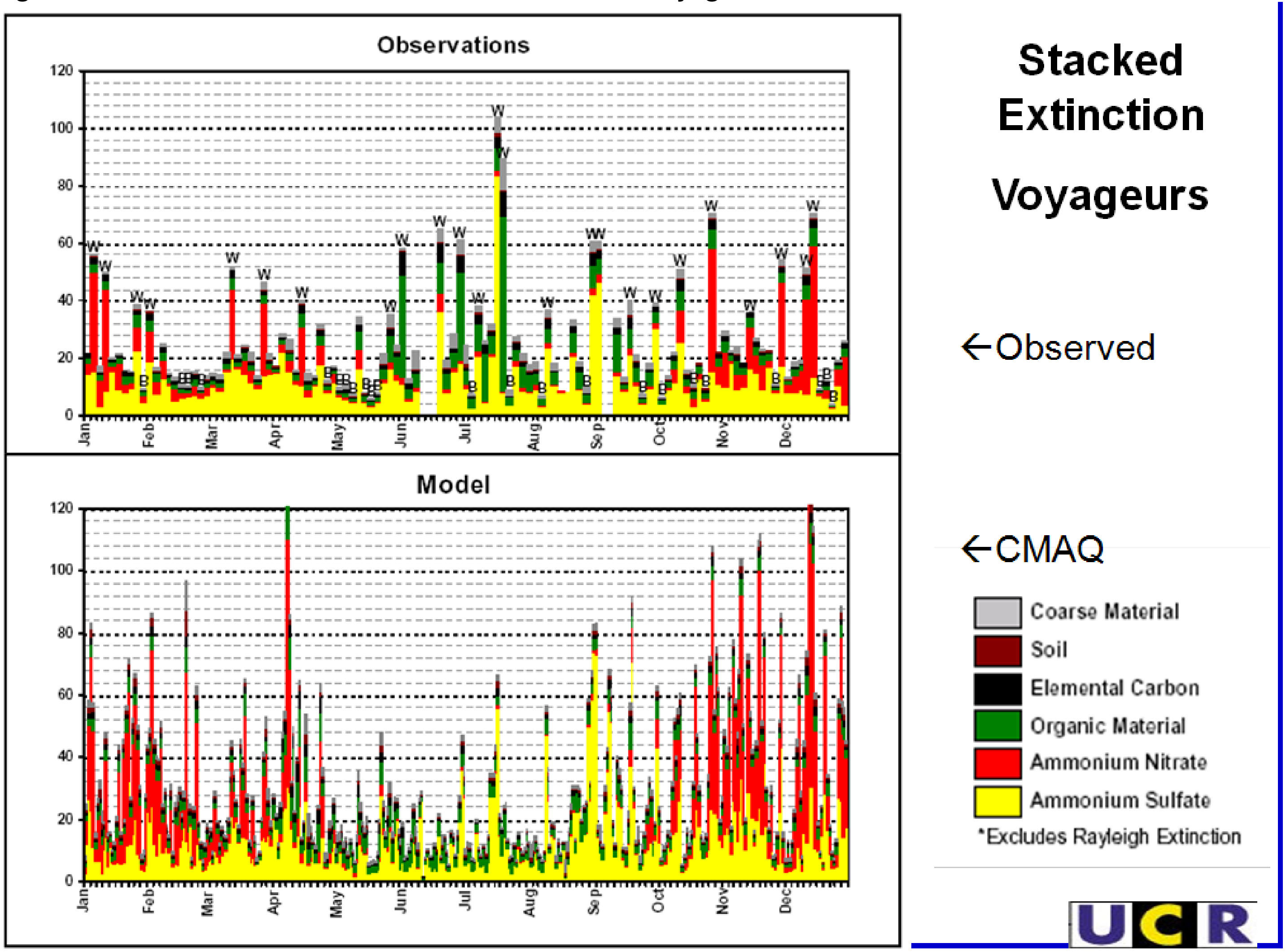
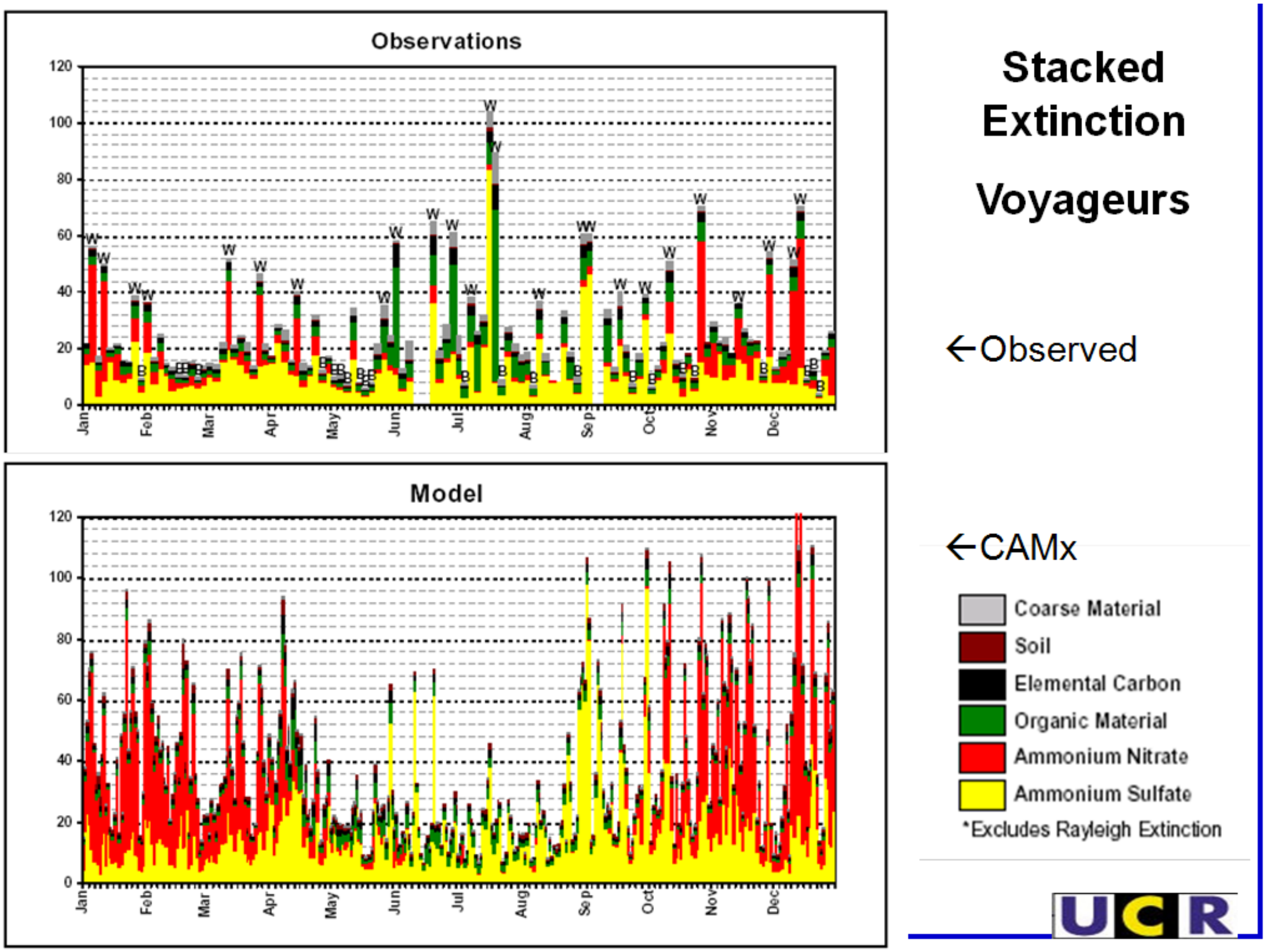


Figure B-5 CAMx vs. Observed Haze Predictions at Voyageurs National Park



APPENDIX C

Haze Time Series Plots for Voyageurs National Park, Seney Wilderness Area, and Isle Royale National Park

Figure C-1 Time Series of Nitrate Haze at Voyageurs National Park (2002-2010)

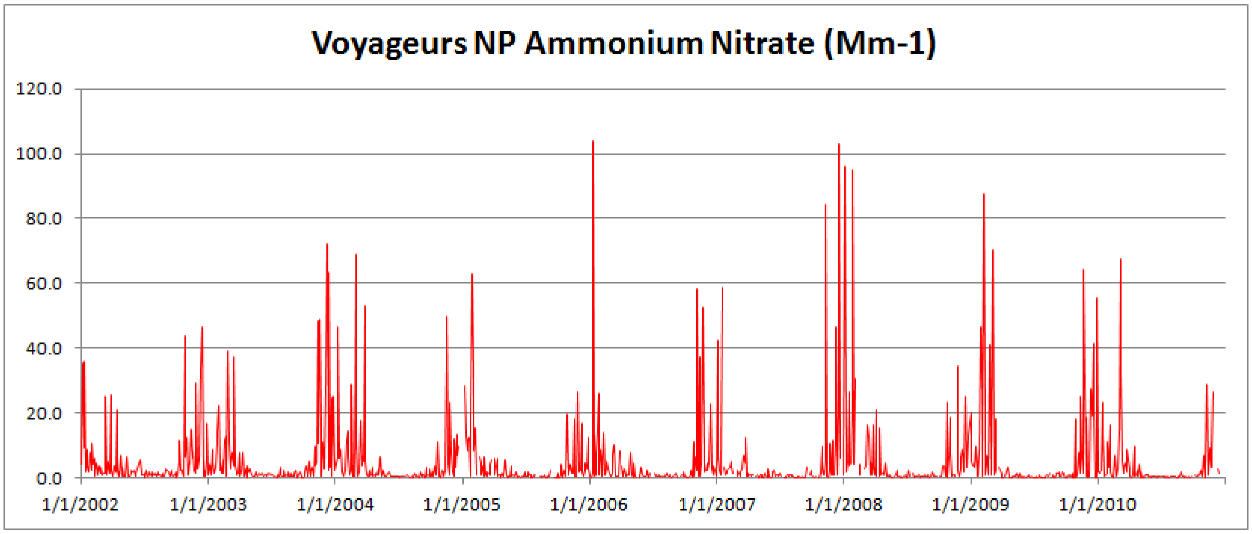


Figure C-2 Time Series of Sulfate Haze at Voyageurs National Park (2002-2010)

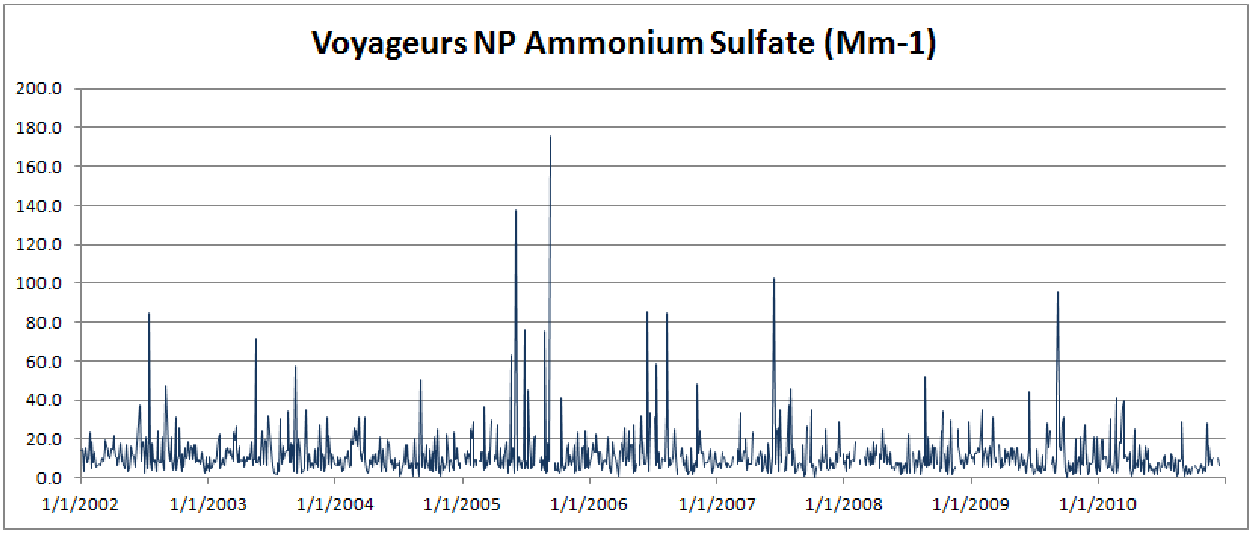


Figure C-3 Time Series of Nitrate Haze at Seney Wilderness Area (2002-2010)

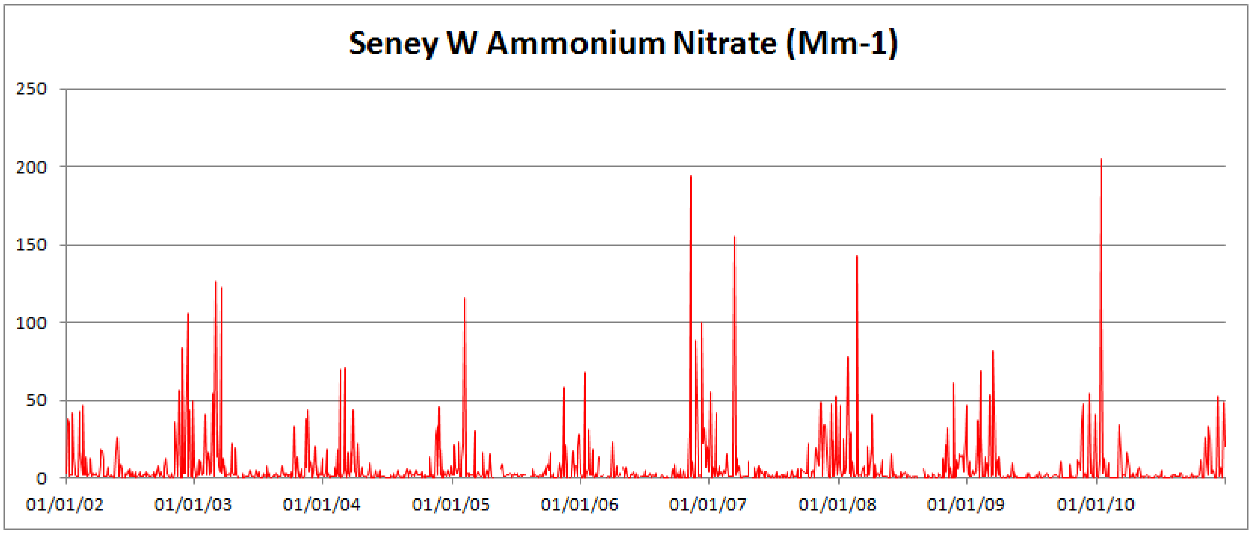


Figure C-4 Time Series of Sulfate Haze at Seney Wilderness Area (2002-2010)

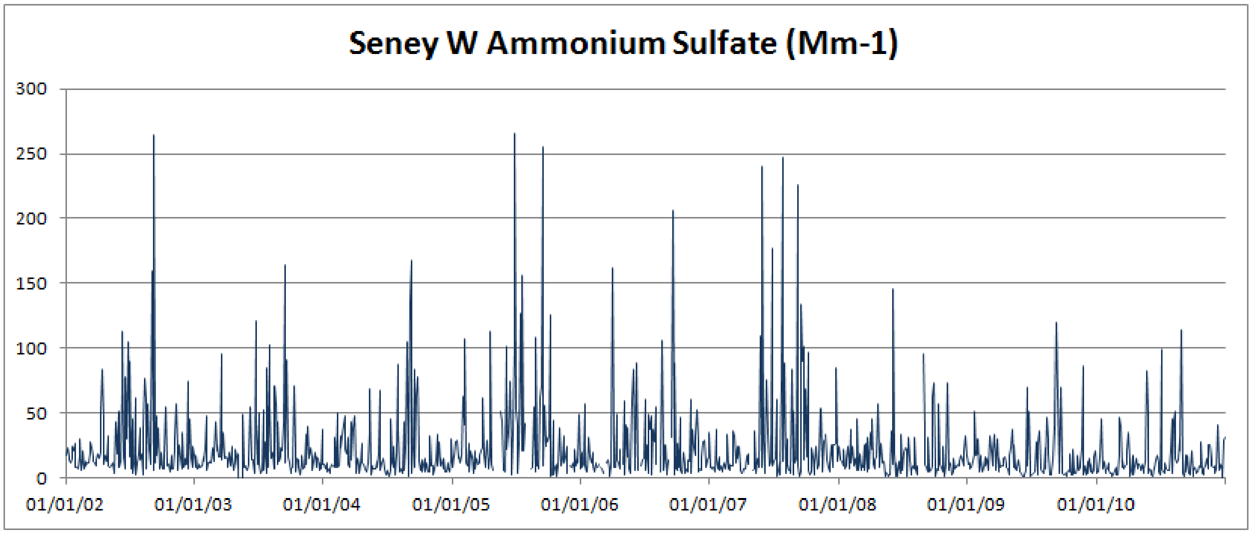


Figure C-5 Time Series of Nitrate Haze at Isle Royale National Park (2002-2010)

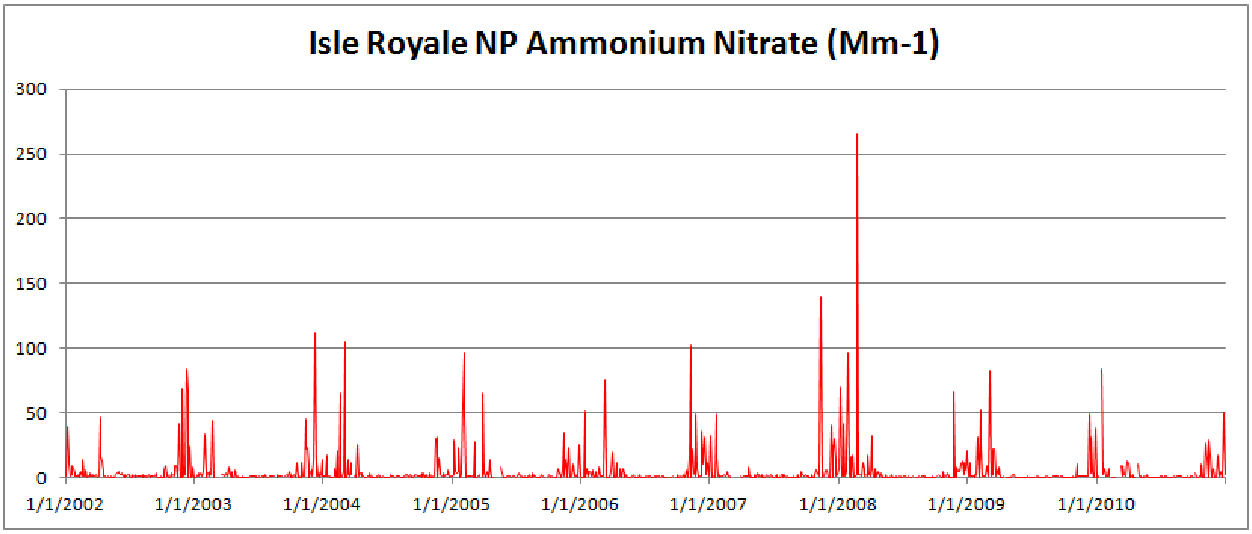
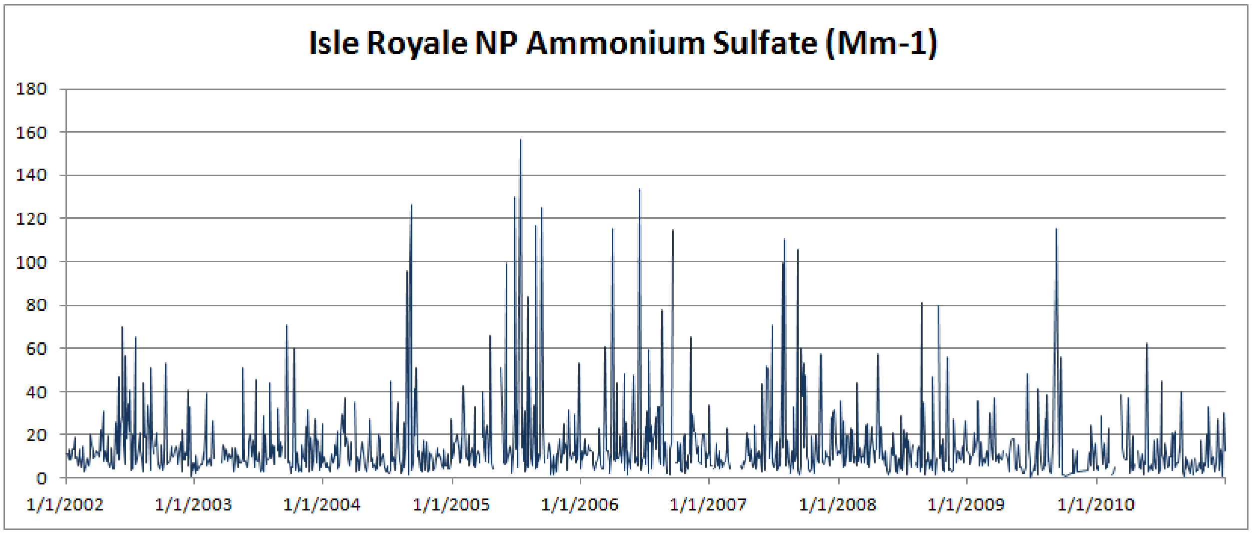


Figure C-6 Time Series of Sulfate Haze at Isle Royale National Park (2002-2010)



APPENDIX D

EXAMPLE OF VISIBILITY CHANGES AFTER ACTUAL EMISSION REDUCTIONS: SHUTDOWN OF THE MOHAVE GENERATING STATION

The Mohave Generating Station (MGS) shut down at the end of 2005, which should have had a large, beneficial effect (over 2 dv, according to CALPUFF) upon Grand Canyon visibility on the 98th percentile worst days. The MGS was a large (1590 MW) coal-fired plant located near the southern tip of Nevada (Laughlin, NV). MGS was placed in operation in the early 1970s, and was retired at the end of 2005 as a result of a consent agreement with the United States Environmental Protection Agency (EPA). The agreement had provided MGS with the option of continued operation if state-of-the-art emissions controls were installed for SO_2 and NOx emissions, but the owners determined that the cost of controls was too high to justify the investment. As a result, the plant was shut down on December 31, 2005 and has not been in operation since then.

As shown in Figure C-1, the MGS location is about 115 km away from the closest point of the Grand Canyon National Park, for which a southwesterly wind is needed to carry the emissions from MGS to most of the park. A multi-year study[39] completed by the EPA in 1999 (Project MOHAVE) indicated that MGS could be a significant contributor to haze in the Grand Canyon. In fact, typical annual emissions from MGS during the last several years of operation were approximately 40,000 tons per year (TPY) of SO_2 and 20,000 TPY of NOx. EPA noted in their Project MOHAVE conclusions that due to this level of emissions of haze precursors and its proximity to the Grand Canyon, MGS was the single largest emission source that could cause regional haze within the Grand Canyon.

Haze observations at three locations in the Grand Canyon (Meadview, Indian Garden, and Hance Camp monitors are available every third day for periods both before and after the plant shut down at the end of 2005. By comparing haze measurements before and after plant shutdown, it may be possible to determine whether the haze in the Grand Canyon has perceptibly changed since 2005 by reviewing the data from these three monitors. The Meadview monitor is at the western edge of the Park, and is relatively close to MGS. The other two IMPROVE monitors are located near some of the most heavily visited areas of the park (Hance Camp, on the South Rim, and Indian Garden, about 1,100 feet lower near the bottom of the canyon).

A 2010 *Atmospheric Environment* paper by Terhorst and Berkman[40] studied the effects of the opportunistic "experiment" afforded by the abrupt shutdown of the largest source affecting the Grand Canyon (according to EPA). The paper noted that Project MOHAVE's conclusions about the effects of MGS on the Grand Canyon visibility were ambiguous. The project's tracer studies revealed that while the MGS emissions did reach the park, particularly in the summer, there was no evidence linking these elevated concentrations with actual visibility impairment; indeed, "correlation between measured tracer concentration and both particulate sulfur and light extinction were virtually nil."

On the other hand, dispersion models produced results inconsistent with the observations. Noting the disconnect between the measurements and model predictions, EPA noted the disparity between the measurements and modeling results, but still appeared to favor the models when it concluded that MGS was the largest sole contributor to visibility impairment in the Grand Canyon.

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[39] Pitchford, M., Green, M., Kuhns, H., Scruggs, M., Tombach, I., Malm, W., Farber, R., Mirabella, V., 1999. Project MOHAVE: Final Report. Tech. Rep., U.S. Environmental Protection Agency (EPA).

[40] Jonathan Terhorst and Mark Berkman. "Effect of Coal-Fired Power Generation on Visibility in a Nearby National Park," Atmospheric Environment, 44(2010) 2544-2531. This publication is available by request from Mark Berkman at mark.berkman@berkeleyeconomics.com.

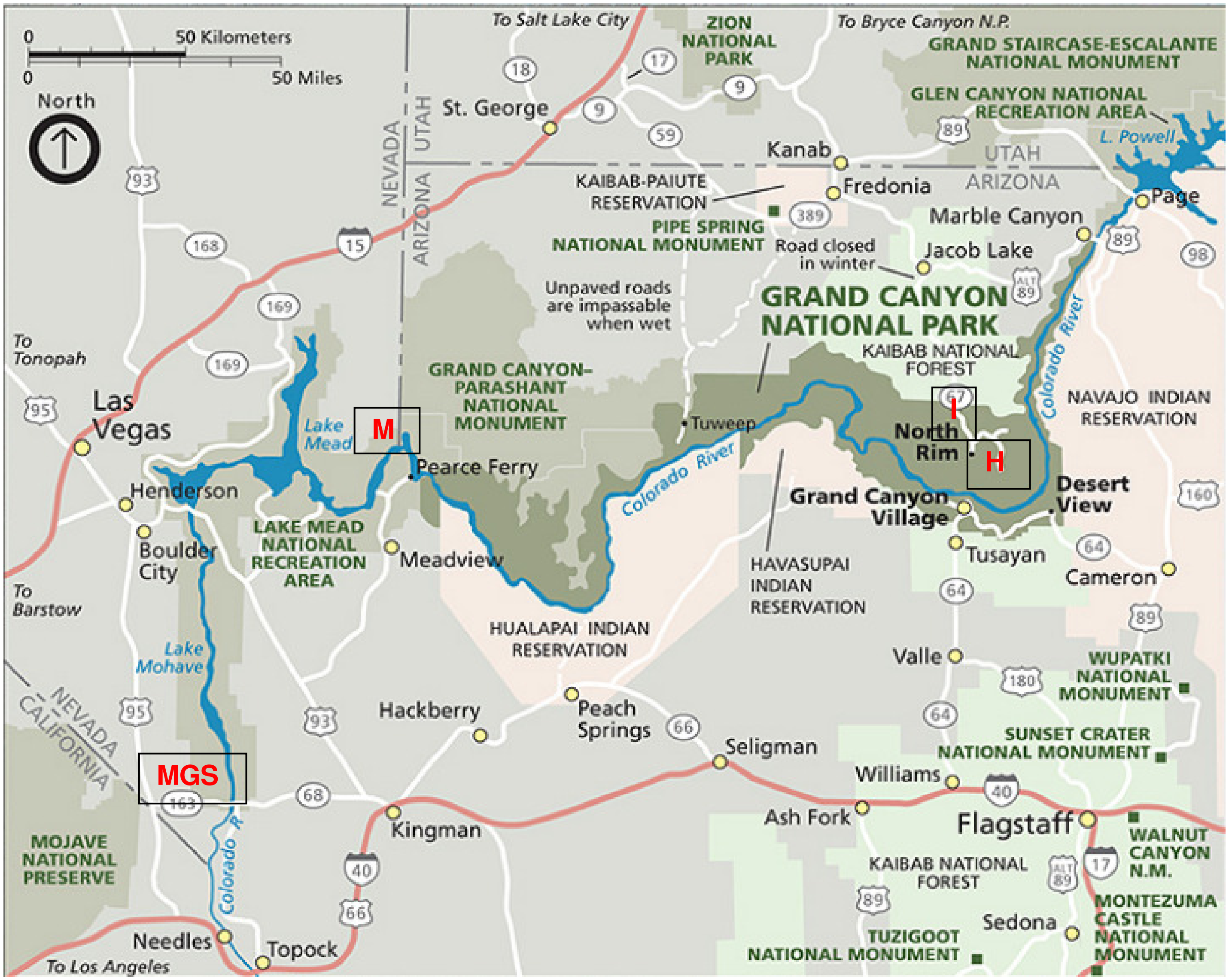
According to the authors, the Project Mohave observations were consistent with observations during temporary outages of MGS, for which there were no reports of substantial changes to visibility in the Grand Canyon.

Best Available Retrofit Technology (BART) studies evaluated a possible conversion of MGS to natural gas firing in 2008. These studies used the CALPUFF dispersion model in a manner prescribed by EPA to determine the change in visibility between the baseline emissions associated with coal firing to the natural gas firing alternative. The BART analyses conducted by the Nevada Department of Environmental Protection indicated that large differences in haze would result: an improvement of about 2.4 deciviews for the 98th percentile peak day, and a haze reduction to below 0.5 deciview on 186 days over 3 years modeled. Since natural gas firing would eliminate nearly all of the SO_2 emissions (although not all of the NOx emissions) this modeled result would tend to underestimate the visibility improvement that would be anticipated with a total plant shutdown.

Terhorst and Berkman analyzed several statistics to determine the change in sulfate concentrations and visibility in the Grand Canyon between the period 2003-2005 (pre-shutdown) and the period 2006-2008 (post-shutdown). They also considered other areas to determine how other regional and environmental effects might be reflected in changes at the Grand Canyon. Terhorst and Berkman calculated the average visibility over all IMPROVE monitoring days between 2003-2005 and 2006-2008, and determined that the average visibility was unchanged at Meadview, slightly improved on the South Rim (Hance Camp), and slightly worse at Indian Garden. Consistent with the observations of minimal visibility impact of MGS during Project MOHAVE, they concluded that the closure of MGS had a relatively minor effect on visibility in the Grand Canyon. These authors questioned the veracity of CALPUFF modeling (e.g., for BART) in that it predicts relatively large improvements in the Grand Canyon visibility that are not borne out by observations.

Emissions reductions associated with the shutdown of the Mohave Generating Station at the end of 2005 have provided an opportunistic means to discern the effect of retrofitting emission controls on coal-fired power plants in the western United States. In the case of MGS, although EPA had determined that this facility was the single most important contributor to haze in the Grand Canyon National Park and CALPUFF modeling using EPA's BART procedures provided predictions of significant improvements in haze, actual particulate and haze measurements taken before and after the shutdown do not reflect the large reductions that would be anticipated from these studies. This may be due in part to the fact that there are several aspects to the CALPUFF modeling procedures that greatly inflate the predicted haze (as noted below), and therefore, the predicted improvements due to emission reductions.

Figure D-1 : Map Showing the Relationship of the Mohave Generating Station to the Grand Canyon National Park



http://www.nps.gov/grca/planyourvisit/upload/GRCAmap2.pdf

H: Hance Camp monitor

I: Indian Garden monitor

M: Meadview monitor

Regional Haze Four-Factor Analysis Applicability Evaluation

Rotary Kilns Lines 3-7

Prepared for
United States Steel Corporation, Minnesota Ore Operations - Minntac

May 29, 2020

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Regional Haze Four-Factor Analysis Applicability Evaluation

May 29, 2020

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Appendix A Visibility Impacts

1 Executive Summary

On January 29, 2020 the Minnesota Pollution Control Agency (MPCA) submitted a Request for Information (RFI) Letter[1] to United States Steel Corporation, Minnesota Ore Operations - Minntac (Minntac) to consider potential emissions reduction measures of nitrogen oxides (NO_X) and sulfur dioxide (SO_2) from the facility's indurating furnaces by addressing the four statutory factors laid out in 40 CFR 51.308(f)(2)(i), as explained in the August 2019 U.S. EPA Guidance (2019 Guidance)[2]:

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

Emission reduction evaluations addressing these factors are commonly referred to as "four-factor analyses." MPCA set a July 31, 2020 deadline for Minntac to submit a four-factor analysis. The MPCA intends to use the four-factor analyses to evaluate additional control measures as part of the development of the State Implementation Plan (SIP), which must be submitted to United States Environmental Protection Agency (USEPA) by July 31, 2021. The SIP will be prepared to address the second regional haze implementation period, which ends in 2028.

This report considers whether a four-factor analysis is warranted for Minntac because the rotary kilns can be classified as "effectively controlled" sources for NO_x and SO_2. The MPCA can exclude such sources for evaluation per the regulatory requirements of the Regional Haze Rule[3] (RHR) and the 2019 Guidance.

This report provides evidence that it would be reasonable for MPCA to exclude Minntac from the group of sources analyzed for control measures for the second implementation period and to withdraw its request for a four-factor analysis for the rotary kilns based on the following points (with additional details provided in cited report sections):

- The rotary kilns meet the BART-required control equipment installation scenario and are "effectively controlled" sources for NO_x and SO_2. Minntac has BART emission controls and emission limits for NO_X and SO_2 in accordance with 40 CFR 52.1235(b)(1) and 52.1235(b)(2), respectively. The associated BART analyses are provided in the August 2012[4] and October 2015[5] USEPA Federal Implementation Plan (FIP) rulemaking. (see Section 5)

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[1] January 29, 2020 letter from Hassan Bouchareb of MPCA to United States Steel Corporation – Minnesota Ore Operations - Minntac.

[2] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[3] USEPA, Regional Haze Rule Requirements – Long Term Strategy for Regional Haze, 40 CFR 52.308(f)(2)

[4] USEPA, Federal Register, 08/15/2012, Page 49308.

[5] USEPA, Federal Register, 10/22/2015, Page 64160.

- The RHR and the 2019 Guidance both give states the ability to focus their analyses in one implementation period on a set of sources that differ from those analyzed in another implementation period. (see Section 2.1.3.2)
- There has been significant progress on visibility improvement in the nearby Class I areas and MPCA's reasonable progress goals should be commensurate with this progress. (see Section 3.1)
- The rotary kilns do not materially impact visibility from a theoretical (modeling) and empirical (actual visibility data) basis and should not be required to assess additional emission control measures. (see Section 4)

Additional emission reductions from the rotary kilns at Minntac will not contribute meaningfully to further reasonable progress. Therefore Minntac requests MPCA withdraw its request for a four-factor analysis for the rotary kilns.

2 Introduction

Section 2.1 discusses the RFI provided to Minntac by MPCA, pertinent regulatory background for regional haze State Implementation Plans (SIP) development and relevant guidance issued by USEPA to assist States in preparing their SIPs, specifically regarding the selection of sources that must conduct an emissions control evaluation. Section 2.2 provides a description of Minntac's indurating furnaces.

2.1 Regulatory Background

2.1.1 Minnesota's Request for Information (RFI)

"Regional haze" is defined at 40 CFR 51.301 as "visibility impairment that is caused by the emission of air pollutants from numerous anthropogenic sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources." The RHR requires state regulatory agencies to submit a series of SIPs in ten-year increments to protect visibility in certain national parks and wilderness areas, known as mandatory Federal Class I areas. The original State SIPs were due on December 17, 2007 and included milestones for establishing reasonable progress towards the visibility improvement goals, with the ultimate goal to achieve natural background visibility by 2064. The initial SIP was informed by best available retrofit technology (BART) analyses that were completed on all BART-subject sources. The second RHR implementation period ends in 2028 and requires development and submittal of a comprehensive SIP update by July 31, 2021.

As part of the second RHR implementation period SIP development, the MPCA sent an RFI to Minntac on January 29, 2020. The RFI stated that data from the IMPROVE (Interagency Monitoring of Protected Visual Environments) monitoring sites at Boundary Waters Canoe Area (BWCA) and Voyageurs National Park (Voyageurs) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of SO_2 and NO_X that react with available ammonia. In addition, emissions from sources in Minnesota could potentially impact Class I areas in nearby states, namely Isle Royale National Park (Isle Royale) in Michigan.[6] As part of the planning process for the SIP development, MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to evaluate regional emission reductions.

The RFI also stated that Minntac was identified as a significant source of NO_X and SO_2 and is located close enough to the BWCA and Voyageurs to potentially cause or contribute to visibility impairment. Therefore, the MPCA requested that Minntac submit a "four-factors analysis" (herein termed as a "four-factor analysis") evaluating potential emissions control measures, pursuant to 40 CFR 51.308(f)(2)(i)[7], by July 31, 2020 for the emission units identified in Table 2-1.

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[6] Although Michigan is responsible for evaluating haze in Isle Royale, it must consult with surrounding states, including Minnesota, on potential cross-state haze pollution impacts.

[7] The four statutory factors are 1) cost of compliance, 2) time necessary for compliance, 3) energy and non-air quality environmental impacts of compliance, and 4) remaining useful life of the source.

Table 2-1 Identified Emission Units

Unit	Unit ID	Applicable Pollutants
Line 3 Rotary Kiln	(EQUI 146/EU 225)	NO_X, SO_2
Line 4 Rotary Kiln	(EQUI 279/EU 261)	NO_X, SO_2
Line 5 Rotary Kiln	(EQUI 280/EU 282)	NO_X, SO_2
Line 6 Rotary Kiln	(EQUI 3/EU 315)	NO_X, SO_2
Line 7 Rotary Kiln	(EQUI 179/EU 334)	NO_X, SO_2

The RFI to Minntac specified that the "analysis should be prepared using the U.S. Environmental Protection Agency guidance" referring to USEPA guidance as issued on August 20, 2019[8].

2.1.2 SIP Revision Requirements

The regulatory requirements for comprehensive revisions to the SIP are provided in 40 CFR 51.308(f). The next revision must be submitted to USEPA by July 31, 2021 and must include a commitment to submit periodic reports describing progress towards the reasonable progress goals as detailed in 40 CFR 51.308(g). The SIP "must address regional haze in each mandatory Class I Federal area located within the State and in each mandatory Class I Federal area located outside the State that may be affected by emissions from within the State."

Each SIP revision is required to address several elements, including "calculations of baseline, current, and natural visibility conditions; progress to date; and the uniform rate of progress."[9] The baseline conditions are based on monitoring data from 2000 to 2004 while the target conditions for natural visibility are determined using USEPA guidance. The State will then determine the uniform rate of progress (URP) which compares "the baseline visibility condition for the most impaired days to the natural visibility condition for the most impaired days and determine the uniform rate of visibility improvement (measured in deciviews of improvement per year) that would need to be maintained during each implementation period in order to attain natural visibility conditions by the end of 2064."[10]

The SIP revision must also include the "Long-term strategy for regional haze."[11] The strategy "must include the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress" towards the natural visibility goal. There are several criteria that must be considered when developing the strategy, including an evaluation of emission controls (the four-factor analysis) at selected facilities to determine emission reductions necessary to make reasonable progress. The SIP must consider other factors in developing its long-term strategy, including: emission reductions due to other air pollution control programs[12], emission unit retirement and replacement

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[8] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[9] 40 CFR 51.308(f)(1)

[10] 40 CFR 51.308(f)(1)(vi)(A)

[11] 40 CFR 51.308(f)(2)

[12] 51.308(f)(2)(iv)(A)

schedules[13], and the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions during the implementation period[14].

In addition, the SIP must include "reasonable progress goals" that reflect the visibility conditions that are anticipated to be achieved by the end of the implementation period through the implementation of the long term strategy and other requirements of the Clean Air Act (CAA)[15]. The reasonable progress goal is not enforceable but will be considered by USEPA in evaluating the adequacy of the SIP[16].

2.1.3 USEPA Guidance for SIP Development

On August 20, 2019, the USEPA issued "*Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*"[17] USEPA's primary goal in issuing the 2019 Guidance was to help states develop "approvable" SIPs. EPA also stated that the document supports key principles in SIP development, such as "leveraging emission reductions achieved through CAA and other programs that further improve visibility in protected areas."[18]

The 2019 Guidance says SIPs must be "consistent with applicable requirements of the CAA and EPA regulations, and are the product of reasoned decision-making"[19] but also emphasizes States' discretion and flexibility in the development of their SIPs. For instance, the 2019 Guidance states, "A key flexibility of the regional haze program is that a state is *not* required to evaluate all sources of emissions in each implementation period. Instead, a state may reasonably select a set of sources for an analysis of control measures."[20] The 2019 Guidance notes this flexibility to not consider every emission source stems directly from CAA § 169A(b)(2) and 40 CFR § 51.308(f)(2)(i), the section of the RHR the MPCA cites in its letter.[21]

The 2019 Guidance lists eight key process steps that USEPA anticipates States will follow when developing their SIPs. This report focuses on the selection of sources which must conduct a four-factor analysis and references the following guidance elements which impact the selection:

- Ambient data analysis (Step 1), including the progress, degradation and URP glidepath checks (Step 7)
- Selection of sources for analysis (Step 3), with a focus on:
    - Estimating baseline visibility impacts for source selection (Step 3b)

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[13] 51.308(f)(2)(iv)(C)

[14] 51.308(f)(2)(iv)(E)

[15] 40 CFR 51.308(f)(3)

[16] 40 CFR 51.308(f)(3)(iii)

[17] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[18] Ibid, page 1.

[19] Ibid.

[20] Ibid, page 9 (emphasis added).

[21] Ibid.

- Sources that already have effective emission control technology in place (Step 3f)

2.1.3.1 Ambient Data Analysis

As stated in Section 2.1.2, the RHR requires each state with a Class I area to calculate the baseline, current, and natural visibility conditions as well as to determine the visibility progress to date and the URP. The visibility metric is based on the 20% most anthropogenically impaired days and the 20% clearest days, with visibility being measured in deciviews (dv). The guidance provides the following equation for calculating the Uniform Rate of Progress (URP):[22]

$$\text{URP} = [(\text{2000-2004 visibility})_{\text{20\% most impaired}} - (\text{natural visibility})_{\text{20\% most impaired}}]/60$$

The visibility from 2000-2004 represents the baseline period, and the natural visibility goal is in 2064, which is why the URP is calculated over a 60-year period.

At the end of the SIP development process a State must estimate the visibility conditions for the end of the implementation period and then must complete a comparison of the reasonable progress goals to the baseline visibility conditions and the URP glidepath. The guidance explains that the RHR does not define the URP as the target for "reasonable progress" and further states that if the 2028 estimate is below the URP glidepath, that does not exempt the State from considering the four-factor analysis for select sources.[23] However, the current visibility conditions compared to the URP glidepath will be a factor when determining the reasonable progress goal.

In Section 3, Barr evaluates the visibility improvement progress to date at BWCA, Voyageurs and Isle Royale using the IMPROVE network visibility data from MPCA's website. This analysis was conducted to document the current visibility conditions compared to the URP, which can provide insight into the amount of emission reductions necessary to have the 2028 visibility conditions below the URP.

2.1.3.2 Selection of sources for analysis

The 2019 Guidance emphasizes that the RHR provides flexibility in selecting sources that must conduct an emission control measures analysis:

> "…a state is not required to evaluate all sources of emissions in each implementation period. Instead, a state may reasonably select a set of sources for an analysis of control measures…."[24]

The 2019 Guidance goes on to justify this approach (emphasis added):

> "Selecting a set of sources for analysis of control measures in each implementation period is also consistent with the Regional Haze Rule, which sets up an iterative planning process and anticipates that a state may not need to analyze control measures for all its sources in a given SIP revision. Specifically, section 51.308(f)(2)(i) of the Regional Haze Rule requires a SIP to include a

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[22] Ibid, Page 7.

[23] Ibid, Page 50.

[24] Ibid, Page 9.

> description of the criteria the state has used to determine the sources or groups of sources it evaluated for potential controls. Accordingly, it is reasonable and permissible for a state to distribute its own analytical work, and the compliance expenditures of source owners, over time by addressing some sources in the second implementation period and other sources in later periods. For the sources that are not selected for an analysis of control measures for purposes of the second implementation period, it may be appropriate for a state to consider whether measures for such sources are necessary to make reasonable progress in later implementation periods."[25]

The 2019 Guidance further states that there is not a list of factors that a state must consider when selecting sources to evaluate control measures, but the state must choose factors and apply them in a reasonable way to make progress towards natural visibility. The guidance details several factors that could be considered, including:

- the in-place emission control measures and, by implication, the emission reductions that are possible to achieve at the source through additional measures[26]
- the four statutory factors (to the extent they have been characterized at this point in SIP development)[27]
- potential visibility benefits (also to the extent they have been characterized at this point in SIP development)[28]
- sources already having effective emissions controls in place[29]
- emission reductions at the source due to ongoing air pollution control programs[30]
- in-state emission reductions due to ongoing air pollution control programs that will result in an improvement in visibility[31]

Furthermore, the 2019 Guidance states that "An initial assessment of projected visibility impairment in 2028, considering growth and on-the books controls, can be a useful piece of information for states to consider as they decide how to select sources for control measure evaluation."[32]

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[25] Ibid, Page 9.

[26] Ibid, Page 10.

[27] Ibid.

[28] Ibid.

[29] Ibid, Page 21.

[30] Ibid, Page 22.

[31] Ibid.

[32] Ibid, Page 10.

2.1.3.2.1 Estimating Baseline Visibility Impacts for Source Selection

When selecting sources to conduct an emission control evaluation, the 2019 Guidance says that the state may use a "reasonable surrogate metrics of visibility impacts." The guidance provides the following techniques to consider and says that "other reasonable techniques" may also be considered[33]:

- Emissions divided by distance (Q/d)
- Trajectory analyses
- Residence time analyses
- Photochemical modeling

In regards to documenting the source selection process, the 2019 Guidance states:[34]

> "EPA recommends that this documentation and description provide both a summary of the state's source selection approach and a detailed description of how the state used technical information to select a reasonable set of sources for an analysis of control measures for the second implementation period. The state could include qualitative and quantitative information such as: the basis for the visibility impact thresholds the state used (if applicable), additional factors the state considered during its selection process, and any other relevant information."

In Section 4, Barr presents a trajectory analysis using data from the IMPROVE monitoring network as presented on MPCA's website and photochemical modeling results to demonstrate that it is not appropriate to select the taconite indurating furnaces as sources subject to the emissions control measures analysis because reducing the emissions will not have a large impact on visibility. Section 4 also presents information from the IMPROVE monitoring system which demonstrates that there was not a noticeable improvement in visibility in 2009 when the taconite plants experienced a production curtailment due to a recession which indicates that the reduction of pollutants from taconite facilities will not result in a discernable visibility improvement in the Class 1 areas.

2.1.3.3 Sources that Already have Effective Emission Control Technology in Place

The 2019 Guidance identified eight example scenarios and described the associated rationale for when sources should be considered "effectively controlled" and that states can exclude similar sources from needing to complete a "four-factor analysis."[35] One of the "effectively controlled" scenarios is for "BART-eligible units that installed and began operating controls to meet BART emission limits for the first implementation period."[36] USEPA caveats this scenario by clarifying that "states may not categorically exclude all BART-eligible sources, or all sources that installed BART control, as candidates for selection for

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[33] Ibid, Page 12.

[34] Ibid, Page 27.

[35] Ibid, Page 22.

[36] Ibid, Page 25.

analysis of control measures."[37] USEPA further notes that "a state might, however, have a different, reasonable basis for not selecting such sources [BART-eligible and non-BART eligible units that implement BART controls] for control measure analysis."[38]

In Section 5, Barr presents an evaluation of the BART-eligible units scenario and demonstrates that the rotary kilns are "effectively controlled" sources for both NO_X and SO_2. Thus, a four-factor analysis is not warranted for this source because, as USEPA notes, "it may be unlikely that there will be further available reasonable controls for such sources."[39]

2.2 Facility Description

Minntac mines iron ore (magnetite) and produces taconite pellets that are shipped to steel producers for processing in blast furnaces. The iron ore is crushed and routed through several concentration stages including grinding, magnetic separation, and thickening.

A concentrated iron ore slurry is dewatered by vacuum disc filters, mixed with bentonite, and conveyed to balling drums. Greenballs produced in the balling drums are fed to the traveling grate prior to entering the kiln. The traveling grate consists of drying and preheat zones. After greenballs pass through the traveling grate, they enter the kiln where pellets are heated to approximately 2,400 degrees Fahrenheit to facilitate the conversion of magnetite to hematite. After the kiln, the fired pellets are sent to an annular cooler where ambient air is blown through the pellets, which allows them to be safely discharged onto rubber belting. The heated waste gas from the kiln and annular cooler are used for the drying and heating zones on the traveling grate. Minntac operates five grate/induration kiln (grate-kiln) furnaces. Waste gas from each furnace is controlled by a single venturi wet scrubber and is vented through a single stack.

Figure 2-1 includes a generic sketch of Minntac's grate-kiln furnace designs. Note the schematic does not perfectly represent all Minntac furnace lines. Line 3 does not recirculate cooling air back to the drying zone. Lines 6 and 7 are ported kilns that can inject air directly into the pellet bed.

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[37] Ibid.

[38] Ibid.

[39] Ibid.

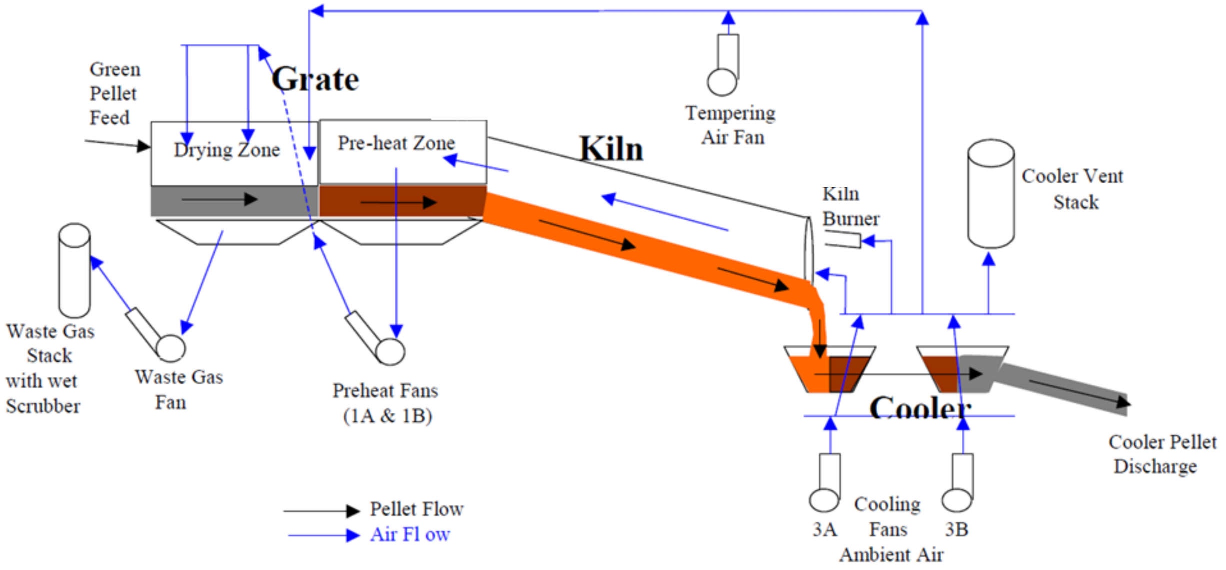

Figure 2-1 Grate-Kiln Furnace Diagram

3 Analysis of Ambient Data

As described in Section 2.1.2, the SIP must consider visibility conditions (baseline, current, and natural visibility), progress to date, and the URP. This requirement is referred to as Step 1 on the 2019 Guidance (see Section 2.1.3.1). This information informs the State's long term strategy for regional haze, as required by 51.308(f)(2), and the reasonable progress goals, as required by 51.308(3).

Section 3.1 provides analysis of visibility conditions based on data from the IMPROVE monitoring network at BWCA (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1) and Section 3.2 addresses regional emission reductions. Consistent with 51.308(f)(2)(iv), the regional emission reductions summary considers emission reductions that have occurred but are not yet reflected in the available 5-year average monitoring data set and future emission reductions that will occur prior 2028, which is the end of the second SIP implementation period.

3.1 Visibility Conditions

As summarized in Section 2.1.2, the RHR requires that the SIP include an analysis "of baseline, current, and natural visibility conditions; progress to date; and the uniform rate of progress."[40] This data will be used in the SIP to establish reasonable progress goals (expressed in deciviews) that reflect the visibility conditions that are projected to be achieved by the end of the implementation period (2028) as a result of the implementation of the SIP and the implementation of other regulatory requirements.[41] The reasonable progress goal is determined by comparing the baseline visibility conditions to natural visibility conditions and determining the uniform rate of visibility improvement needed to attain natural visibility conditions by 2064. The SIP "must consider the uniform rate of improvement in visibility and the emission-reduction measures needed to achieve it for the period covered by the implementation plan."[42]

MPCA tracks progress towards the natural visibility conditions using data from the IMPROVE visibility monitors at BWCA (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1).[43] The available regional haze monitoring data was compared to the uniform rate of progress and to the possible reasonable progress goals for the SIP for the implementation period, which ends in 2028. As described in Section 2.1.3.1, the visibility metric is based on the 20% most anthropogenically impaired days and the 20% clearest days, with visibility being measured in deciviews (dv). USEPA issued guidance for tracking visibility progress, including the methods for selecting the "most impaired days," on December 20, 2018.[44] Originally, the RHR considered the "haziest days" but USEPA recognized that naturally occurring events (e.g., wildfires and dust storms) could be contributing to visibility and that the "visibility improvements resulting from decreases in anthropogenic emissions can be hidden in this uncontrollable natural variability."[45] In

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[40] 40 CFR 51.308(f)(1)

[41] 40 CFR 51.308(f)(3)

[42] 40 CFR 51.308(d)(1)

[43] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

[44] https://www.epa.gov/visibility/technical-guidance-tracking-visibility-progress-second-implementation-period-regional

[45] USEPA, Federal Register, 05/04/2016, Page 26948

addition, the RHR allows a state to account for international emissions "to avoid any perception that a state should be aiming to compensate for impacts from international anthropogenic sources."[46]

Figure 3-1 through Figure 3-3 show the rolling 5-year average of visibility impairment versus the URP glidepath[47] at BWCA (BOWA1), Voyageurs (VOYA2), and Isle Royale (ISLE1). Regional haze impairment has been declining since 2009 for all three Class I areas that are tracked by MPCA. Impacts to the most impaired days at BWCA and Isle Royale fell below the expected 2028 URP goal in 2016 and have continued trending downward since. Voyageurs impaired days fell below the 2028 URP in 2018 and is also on a downward trend.

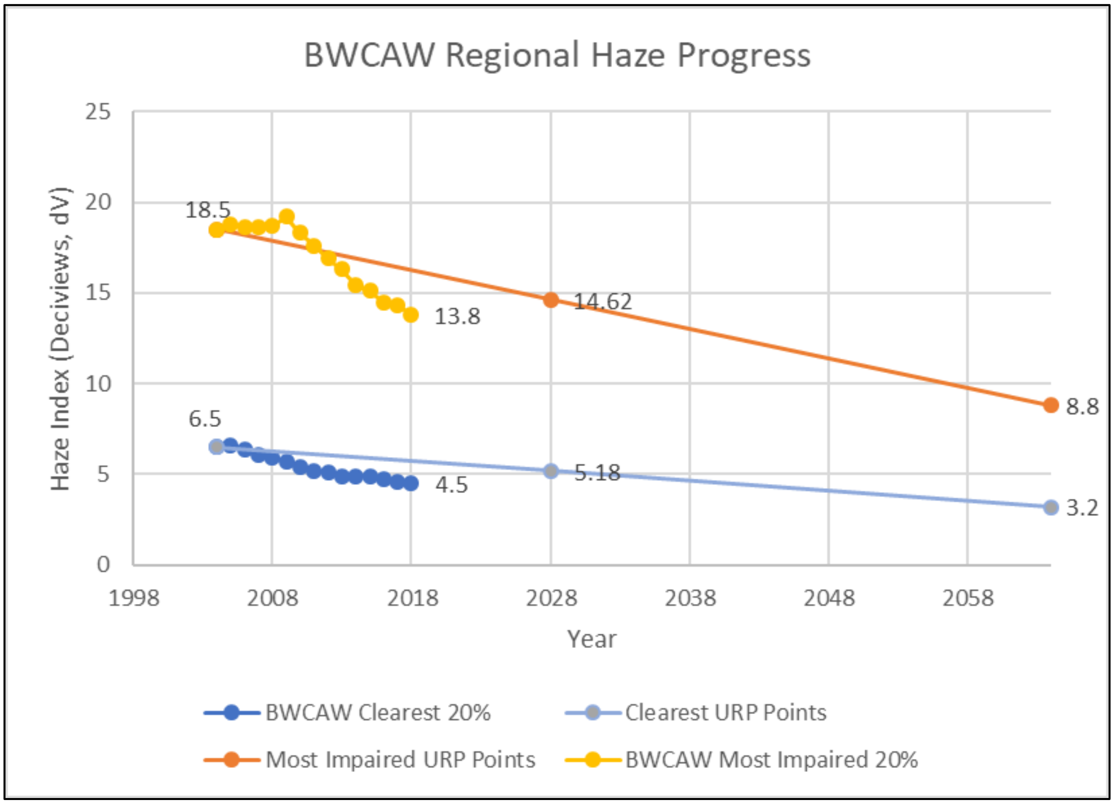

Figure 3-1 Visibility Trend versus URP – Boundary Waters Canoe Area (BOWA1)

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[46] USEPA, Federal Register, 01/10/2017, Page 3104

[47] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

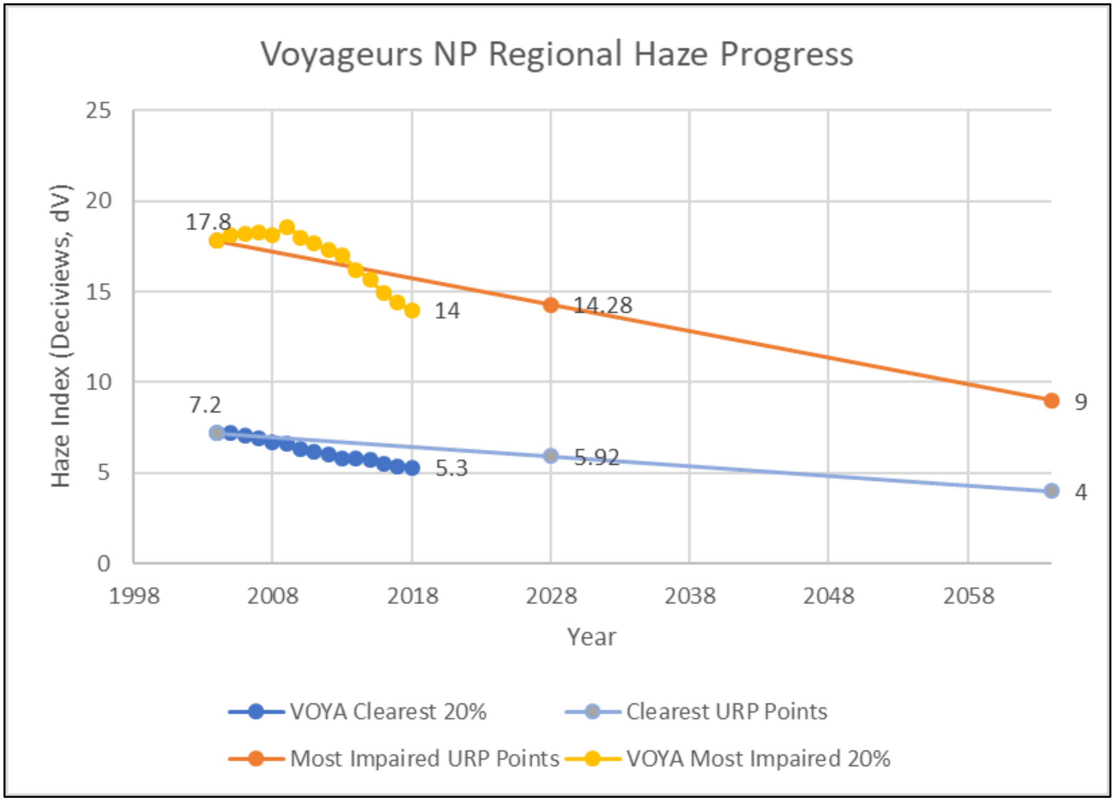

Figure 3-2 Visibility Trend versus URP – Voyageurs National Park (VOYA1)

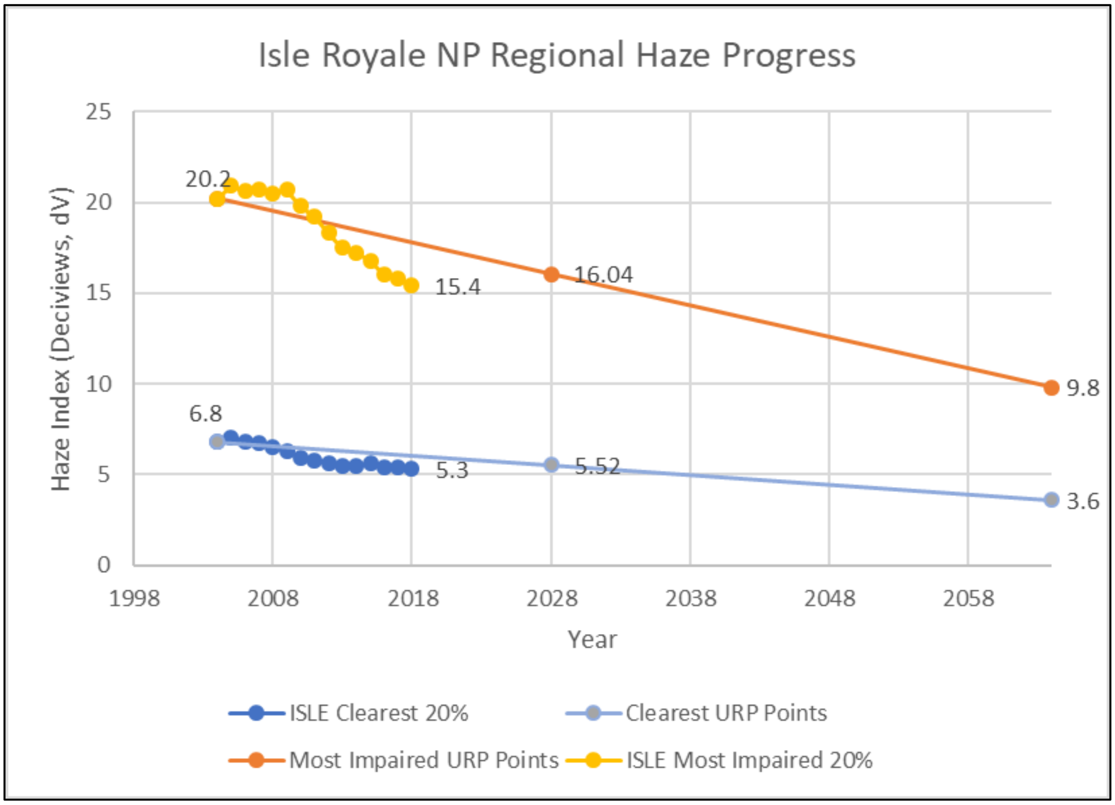

Figure 3-3 Visibility Trend versus URP – Isle Royale National Park (ISLE1)

3.2 Regional emissions reductions

The visibility improvement shown in Figure 3-1 through Figure 3-3 correlates with SO_2 and NO_x emissions decreases from Minnesota's top twenty emission stationary sources, as shown in Figure 3-4[48]. These emission reductions are a result of multiple substantial efforts from the regulated community, including:

- Installation of BART controls during the first implementation period
- Emission reductions at electric utility combustion sources due to new rules and regulations, including:
    - Acid Rain Rules
    - Cross State Air Pollution Rule (CASPR)
    - Mercury and Air Toxics Standards (MATS)
- Electric utility combustion sources undergoing fuel changes (e.g., from coal and to natural gas)
- Increased generation of renewable energy, which decreases reliance on combustion sources

Since many of these emission reduction efforts are due to federal regulations and national trends in electrical generation, similar emission reduction trends are likely occurring in other states.

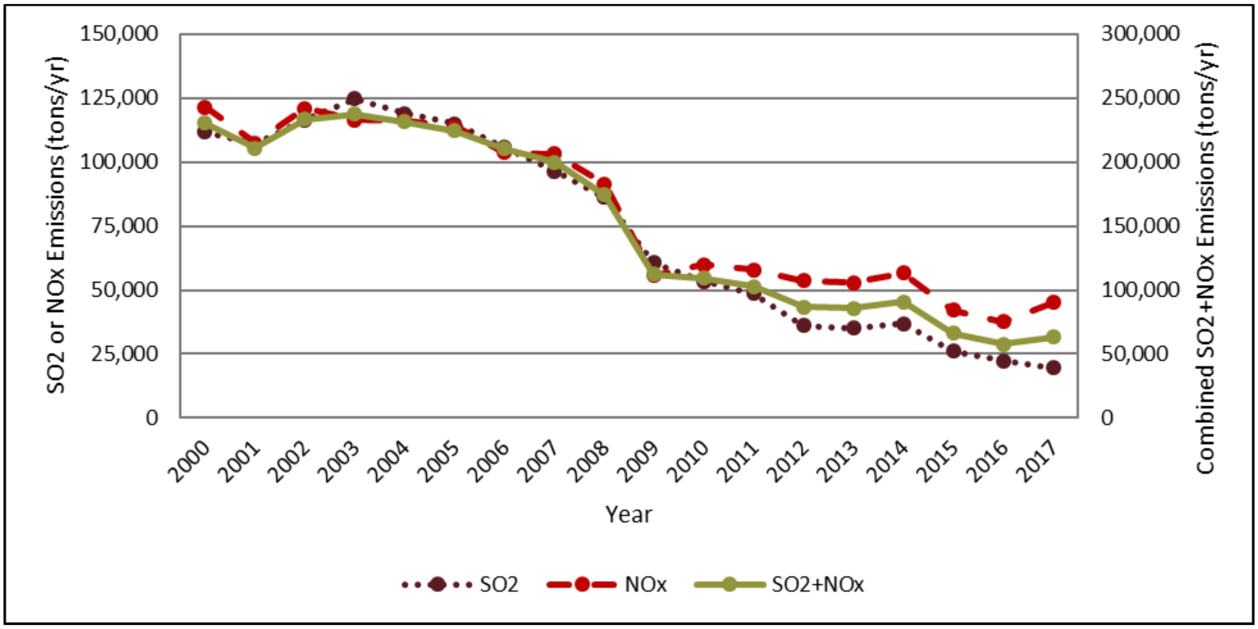

Figure 3-4 Total Emissions of Top-20 Emitters and Taconite Facilities in MN (2000-2017)

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[48] The data for NO_X and SO_2 emissions was downloaded from the MPCA point source emissions inventory (https://www.pca.state.mn.us/air/permitted-facility-air-emissions-data). The permitted facilities that had the 20 highest cumulative emissions from 2000-2017 in MN were chosen for the graphics, along with all six taconite facilities (whether or not they were in the top 20 of the state).

Figure 3-1 through Figure 3-3 show the rolling 5-year average of visibility impairment versus the URP glidepath, so the emissions represented in the most recent data set (2018) is from 2014-2018. However, as shown in Table 3-1, additional emission reductions have occurred since 2014 and are not fully represented in the 5-year visibility data yet. Additionally, several stationary sources have scheduled future emission reductions which will occur prior to 2028. Combined, these current and scheduled emission reductions will further improve visibility in the Class I areas, ensuring the trend stays below the URP. Even without these planned emissions reductions, the 2018 visibility data is already below the 2028 glidepath. As such, MPCA's second SIP implementation period strategy should be commensurate with the region's visibility progress and it would be reasonable for MPCA to not include the taconite indurating furnaces when "reasonably select[ing] a set of sources for an analysis of control measures," and such decision is supported by the 2019 Guidance.

Table 3-1 Notable Minnesota Emission Reductions

Year	Additional Emissions Reductions Expected/Projected
2015	MP Laskin: converted from coal to natural gas**
2017	Minntac Line 6: FIP emission limit compliance date for NO_X*
2018	Minntac Line 7: FIP emission limit compliance date for NO_X* MP Boswell: Units 1 & 2 retired from service**
2019	Hibtac Line 1: FIP emission limit compliance date for NO_X* Keetac: FIP emission limit compliance date for NO_X * Minntac Line 4 or 5: FIP emission limit compliance date for NO_X* Utac Line 1: FIP emission limit compliance date for NO_X*
2020	Hibtac Line 2: FIP emission limit compliance date for NO_X* Minntac Line 4 or 5: FIP emission limit compliance date for NO_X* Minorca: FIP emission limit compliance date for NO_X* Utac Line 2: FIP emission limit compliance date for NO_X*
2021	Minntac Line: FIP emission limit compliance date for NO_X* Hibtac Line 3: FIP emission limit compliance date for NO_X*
2023	Xcel: Sherco Unit 2 Retirement***
2026	Xcel: Sherco Unit 1 Retirement***
2028	Xcel: Allen S. King Plant Retirement***
2030	Xcel: Sherco Unit 3 Retirement, Xcel target to emit 80% less carbon by 2030***
2050	Xcel: Energy targeting carbon free generation by 2050***

* FIP is the regional haze Federal Implementation Plan detailed in 40 CFR 52.1235
** Minnesota Power - Integrated Resource Plan 2015-2029
*** Xcel Energy - Upper Midwest Integrated Resource Plan 2020-2034.

4 Visibility Impacts

As described in Section 2.1.3.2, the 2019 Guidance outlines criteria to evaluate when selecting sources that must complete an analysis of emission controls. The 2019 Guidance is clear that a state does not need to evaluate all sources of emissions but "may reasonably select a set of sources for an analysis of control measures" to make progress towards natural visibility.

As described in Section 2.1.3.2.1, the 2019 Guidance provides recommendations on selecting sources by estimating baseline visibility impacts. Three of the options for estimating baseline visibility impacts are analyzed below:

- *Trajectory analyses*[49]
  In general, these analyses consider the wind direction and the location of the Class I areas to identify which sources tend to emit pollutants upwind of Class I areas. The 2019 Guidance says that a state can consider "back trajectories" which "start at the Class I area and go backwards in time to examine the path that emissions took to get to the Class I areas." Section A1.1 of Appendix A, describes the back trajectory analysis and concludes the taconite indurating furnaces were a marginal contributor to the "most impaired" days from 2009 and 2011-2015. The trajectory analysis also indicates many sources other than the taconite facilities were significant contributors to the "most impaired" days.

- *Photochemical modeling*[50]
  The 2019 Guidance says, "states can also use a photochemical model to quantify source or source sector visibility impacts." CAMx modeling was previously conducted to identify visibility impacts in Class I areas from Minnesota taconite facilities from NOx emission reductions. This analysis is summarized in Section A1.2 of Appendix A which concludes the Class I areas near the Iron Range will not experience any observable visibility improvements from NO_X emission reductions suggested by the USEPA in the final Regional Haze FIP for taconite indurating furnaces.

- *Other reasonable techniques*[51]
  In addition to the two analyses described above which estimate the baseline visibility impacts, Section A1.3 of Appendix A evaluates the actual visibility data against the 2009 economic recession impacts on visibility, when taconite facilities curtailed production. This curtailment resulted in a decrease in emissions from the collective group of taconite plant and the regional power production that is needed to operate the plants. The IMPROVE monitoring data during this curtailment period was compared to monitoring data during more typical production at the taconite plants to estimate the taconite facilities' actual (rather than modeled) impact on haze. This analysis concludes "haze levels in BWCA did not, in general, decrease during 2009, and were therefore unaffected by emission reductions associated with the taconite production slowdown. It

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[49] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, Page 13.

[50] Ibid, Page 14.

[51] Ibid, Page 12.

is noteworthy that peak events during mid-2009 in sulfate haze at BWCA when very little taconite production was occurring clearly indicate that minimal haze reduction would likely be associated with taconite plant emission reductions.”[52] The report further notes “high nitrate haze days late in 2009 with the taconite plant curtailment that are comparable in magnitude to full taconite production periods in 2008. We also note that after the taconite plants went back to full production in 2010, the haze levels dropped, apparently due to emissions from other sources and/or states.”[53]

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[52] AECOM, “Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas,” 09/28/2012, Page 10.

[53] Ibid, Page 12.

5 Evaluation of "Effectively Controlled" Source

As described in Section 2.1.3.3, the 2019 Guidance acknowledges that states may forgo requiring facilities to complete the detailed four-factor analysis if the source already has "effective emission control technology in place."[54] This section demonstrates that the rotary kilns meet USEPA's BART-required control equipment installation scenario for NO_X and SO_2.

The rotary kilns meet this scenario as "effectively controlled" sources because:

- The rotary kilns are BART-eligible units, as determined by Minnesota's December 2009 Regional Haze Plan, and are regulated under 40 CFR 52.1235 (Approval and Promulgation of Implementation Plans – Subpart Y Minnesota – Regional Haze)
- The rotary kilns have controls and must "meet BART emission limits for the first implementation period"[55] for NO_X and SO_2
- In 2016, EPA promulgated a revised FIP that included, among other things, BART requirements to effectively control NOx and SO2 for the Minntac grate kilns[56]

The following sections describe USEPA's BART determinations, the associated controls that were implemented as BART, and the resulting BART emission limits for NO_X and SO_2.

5.1 NO_X BART-required Controls

In the August 2012 proposed rule FR notice preamble,[57] the USEPA concluded that BART for NO_X from grate-kiln furnaces is low-NO_X burner technology. As part of the evaluation, USEPA eliminated the following emission control measures because they were technically infeasible:

- External and Induced Flue Gas Recirculation Burners due to the high oxygen content of the flue gas; [58]

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[54] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, page 22.

[55] Ibid, page 25.

[56] See Federal Register 81, No. 70 (April 12, 2016) 21672. Although the 2012 FIP and the revised 2016 FIP limits for the grate kiln are in litigation, the outcome of that litigation will include BART and what is considered "effectively controlled." Most recently, on February 4, 2020 (See Federal Register 85 No. 23 (February 4, 2020) 6125, EPA proposed BART limits for the Minntac kilns, incorporating the requirements of its agreement with U. S. Steel entered in November 2019. In light of these very recent determinations and actions, it would be inappropriate, inefficient and futile to review the determination that was just proposed a couple of months ago.

[57] Federal Register 77, No. 158 (August 15, 2012); 49311. Available at: https://www.govinfo.gov/app/details/FR-2012-08-15/2012-19789.

[58] Ibid, 49312.

- Energy Efficiency Projects due to the difficulty with assigning a general potential emission reduction for this emission control measure;[59]
- Alternate Fuels due to the uncertainty of environmental and economic benefits[60]; and
- Selective Catalytic Reduction (SCR) controls because of two SCR vendors declining to bid on NO_x reduction testing at the U.S. Steel Minntac facility.[61]

Because the technical feasibility determinations of the listed control measures have not materially changed since the 2016 final FIP, there are no "further available reasonable controls" for NO_X emissions from taconite indurating furnaces. Since the 2016 BART FIP is still in the implementation phase, it is premature and inappropriate to perform another analysis until the requirements of the 2016 FIP have been completed.[62]

In accordance with the FIP, Minntac implemented BART NO_x control measures and the rotary kilns will be or are currently subject to the FIP NO_x emission limits[63] as shown in Table 5-1. Thus, the rotary kilns are considered an "effectively controlled" sources in accordance with the 2019 Guidance and can reasonably be excluded from the requirement to prepare and submit a four-factor analysis for NO_X. In addition, the BART analysis, which was finalized in 2016, already addressed the elements of the four-factor analysis, which further supports eliminating the rotary kilns from the requirement to submit a four-factor analysis[64].

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[59] Ibid.

[60] Ibid, 49313.

[61] Ibid.

[62] As noted above, the 2012 FIP and the revised 2016 FIP limits for the grate kiln are in litigation. For Minntac, in 2019, EPA just completed its evalutioon and determined what is considered "effectively controlled." Most recently, on February 4, 2020 (See Federal Register 85 No. 23 (February 4, 2020) 6125, EPA proposed BART limits for the Minntac kilns, incorporating the requirements of its agreement with U. S. Steel entered in November 2019. In light of these very recent determinations and actions, it would be inappropriate, inefficient and futile to review the determination that was just proposed a couple of months ago.

[63] 40 CFR 52.1235(b)(1)

[64] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, Page 10.

Table 5-1 NO_X Emission Limits

Unit	Unit ID	NO_X Emission Limit (lb/MMBtu)	Compliance Date(1,2)
Line 3 Rotary Kiln	(EQUI 146/EU 225)	1.6	September 1, 2019
Line 4 Rotary Kiln	(EQUI 279/EU 261)		
Line 5 Rotary Kiln	(EQUI 280/EU 282)		
Line 6 Rotary Kiln	(EQUI 3/EU 315)		
Line 7 Rotary Kiln	(EQUI 179/EU 334)		

(1) Compliance date from September 2019 Settlement Agreement. https://s3.amazonaws.com/public-inspection.federalregister.gov/2019-19668.pdf

(2) The revised FIP for Minntac was posted in the Federal Register on February 4, 2020 for public comment. Minntac is awaiting EPA's publication of the final revised FIP. https://www.govinfo.gov/content/pkg/FR-2020-02-04/pdf/2020-01321.pdf

5.2 SO_2 BART-required Controls

In the preamble to the August 2012 proposed FIP[65], the USEPA concluded that BART for SO_2 emissions from the rotary kilns at Minntac is existing controls. As part of the evaluation, USEPA eliminated the following emission control measures because they were technically infeasible:

- Dry Sorbent Injection and Spray Dryer Absorption because the high moisture content of the exhaust would lead to baghouse filter cake saturation and filter plugging[66]
- Alternative Fuels for units burning coal by switching fuels due to the uncertainty of alternative fuel costs, the potential of replacing one visibility impairment pollutant for another, and that BART cannot mandate a fuel switch;[67]
- Coal drying/processing because this requires excess heat source or low-pressure steam, which was not available at Minntac[68]
- Energy Efficiency Projects due to the difficulty with assigning a general potential emission reduction for this emission control measure[69]
- Caustic, lime, or limestone additives to existing scrubbers operating to increase the pH of the scrubbing liquid due to corrosion concerns of the control system that were not designed to operate at a higher pH. The preamble also cited concerns with additional solids and sulfates that would be discharged to the tailing basin and would require extensive treatment to maintain water

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[65] Federal Register 77, No. 158 (August 15, 2012); 49314. Available at: https://www.govinfo.gov/app/details/FR-2012-08-15/2012-19789

[66] Ibid, 49313

[67] Ibid.

[68] Ibid.

[69] Ibid, 49314.

quality and/or would cause an increased blowdown and make-up water rate, which is not available[70]

In addition, USEPA eliminated Wet Walled Electrostatic Precipitator (WWESP) and secondary (polishing) wet scrubber technologies because they were not cost-effective.[71]

Because the technical feasibility and cost effectiveness determinations of the listed control measures have not materially changed since the 2016 final FIP, there are no “further available reasonable controls” for SO_2 emissions from taconite indurating furnaces.

In accordance with the FIP, Minntac has continued to operate the BART SO_2 control measures and is complying with the FIP SO_2 emission limits[72], as shown in Table 5-2. Thus, the rotary kilns are considered “effectively controlled” sources in accordance with the 2019 Guidance and can reasonably be excluded from the requirement to prepare and submit a four-factor analysis for SO_2. In addition, the BART analysis, which was finalized in 2016, already addressed the elements of the four-factor analysis, which further supports eliminating the rotary kilns from the requirement to submit a four-factor analysis[73].

Table 5-2 SO_2 Emission Limits

Unit	Unit ID	SO_2 Emission Limit (flux pellets)⁽¹⁾ (lb/hr)	SO_2 Emission Limit (mix)⁽²⁾ (lb/hr)	SO_2 Emission Limit (acid pellets)⁽³⁾ (lb/hr)	Compliance Date
Line 3 Rotary Kiln	(EQUI 146/EU 225)	498	630	800	June 8, 2013
Line 4 Rotary Kiln	(EQUI 279/EU 261)				
Line 5 Rotary Kiln	(EQUI 280/EU 282)				
Line 6 Rotary Kiln	(EQUI 3/EU 315)				
Line 7 Rotary Kiln	(EQUI 179/EU 334)				

(1) Aggregate limit when all lines are producing flux pellets.
(2) Aggregate limit when Lines 3-5 are producing acid pellets, and Lines 6-7 are producing flux pellets.
(3) Aggregate limit when all lines are producing acid pellets.

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[70] Ibid.

[71] Ibid.

[72] 40 CFR 52.1235(b)(2)

[73] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, Page 10.

6 Conclusion

The preceding sections of this report support the following conclusions:

- The rotary kilns meet the BART-required control equipment installation scenario and are "effectively controlled" sources for NO_X and SO_2 (see Section 5). As stated in the 2019 Guidance, "it may be reasonable for a state not to select an effectively controlled source."[74] Therefore, it would be reasonable and compliant with USEPA requirements to exclude Minntac from further assessments of additional emission control measures.
- There has been significant progress on visibility improvement in the nearby Class I areas and MPCA's reasonable progress goals should be commensurate with this progress (see Section 3):
    - Visibility has improved at all three monitors (BOWA1, VOYA2, and ISLE1) compared to the baseline period
    - Visibility has been below the URP since 2012
    - The 2018 visibility data is below the URP for 2028
    - Additional emissions reductions have continued throughout the region and are not fully reflected in the available 5-year average (2014-2018) monitoring dataset
        - Additional emission reductions are scheduled to occur in the region prior to 2028, including ongoing transitions of area EGUs from coal to natural gas or renewable sources, as well as the installation of low-NO_X burners throughout the taconite industry
- The rotary kilns do not materially impact visibility from a theoretical (modeling) and empirical (actual visibility data) basis and should not be required to assess additional emission control measures. (see Section 4).

The combination of these factors provides sufficient justification for MPCA to justify to USEPA Minntac's exclusion from the group of sources required to conduct a four-factor analysis for this implementation period. Thus, the MPCA should withdraw its request for a four-factor analysis for the rotary kilns.

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[74] Ibid, Page 22

Appendices

Appendix A

Visibility Impacts

A1 Visibility Impacts

A1.1 Trajectory Analysis

The August 2019 U.S. EPA Guidance ("2019 Guidance" or "the Guidance")[1] says that the state may use a "reasonable surrogate metrics of visibility impacts" when selecting sources to conduct an four-factor analysis and cites trajectory analysis as an example of a reasonable technique. This analysis considers reverse trajectories, as provided on MPCA's website[2], to determine the frequency that the trajectories on the "most impaired days"[3] overlapped with a specific area of influence (AOI) on the Iron Range. Data from 2011-2015 were analyzed as this was the most recent five-year period where the taconite facilities were operating under typical production rates.

A particle trajectory analysis is an analysis of the transport path of a particular air mass, including the associated particles within the air mass, to see if the air mass traveled over certain locations from specific source locations. The MPCA tracks visibility via the IMPROVE (Interagency Monitoring of Protected Visual Environments) monitoring sites at Boundary Waters Canoe Area Wilderness (BWCA), Voyageurs National Park (Voyageurs) and Isle Royale National Park (Isle Royale).[4] MPCA's website includes a tool which analyzes reverse trajectories from BWCA and Voyageurs for the "most impaired days" and the clearest days for 2007-2016 to show the regional influence on visibility. The reverse trajectories included in the MPCA tool were developed using the NOAA Hysplit model.[5] The trajectories consist of a single back trajectory for each day of interest, beginning at 18:00 and running back 48 hours with a starting height of 10 meters.

The MPCA Hysplit reverse trajectories from the "most impaired days" were analyzed to identify whether trajectories overlapped with an AOI from certain taconite facilities on the Iron Range. In order to be conservative, Barr estimated an "uncertainty region" for each trajectory based on 20% of the distance traveled for every 10km along the trajectory pathway. This method is consistent with other scientific studies analyzing reverse trajectories and trajectories associated with the NOAA Hysplit model (Stohl - 1998[6], Draxler - 1992[7], Draxler and Hess - 1998[8]). For the purpose of this analysis, the Iron Range AOI was defined as a line connecting the stack at the U. S. Steel Keetac facility with the stack at the ArcelorMittal Minorca Mine and a 3-mile radius surrounding the line. This analysis considers how often the MPCA reverse trajectories overlap the Iron Range AOI on the "most impaired days" to quantitatively determine if the emissions from the Iron Range may have been a contributor to impaired visibility. Attachment 1 to Appendix A includes tables with the annual and seasonal results of this analysis as well as two example figures showing trajectories that cross, and do not cross, the Iron Range AOI.

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[1] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

[2] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Regionalinfluence

[3] "Most impaired days" is the 20% most anthropogenically impaired days on an annual basis, measured in deciviews (dv), as provided on MPCA's website.

[4] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Regionalinfluence

[5] https://www.arl.noaa.gov/hysplit/hysplit/

[6] http://www.kenrahn.com/DustClub/Articles/Stohl%201998%20Trajectories.pdf

[7] https://www.arl.noaa.gov/documents/reports/ARL%20TM-195.pdf

[8] https://www.arl.noaa.gov/documents/reports/MetMag.pdf

As shown in Figure A1 and Figure A2, reverse trajectories from BWCA and Voyageurs in 2011-2015 did not overlap the Iron Range AOI on 62-80%, and 56-71% of "most impaired days", respectively. This means the taconite industry did not influence visibility at BWCA and Voyageurs on the majority of "most impaired days" and suggest that sources other than the taconite facilities are larger contributors to visibility impairment at these sites. Furthermore, the origins of many of the "most impaired day" reverse trajectories are beyond the Iron Range AOI and thus have influences, depending on the trajectory, from other sources (e.g., Boswell Energy Center, Sherburne County Generating Station) or cities such as Duluth, St. Cloud, the Twin Cities, and Rochester as shown in Figure A3.

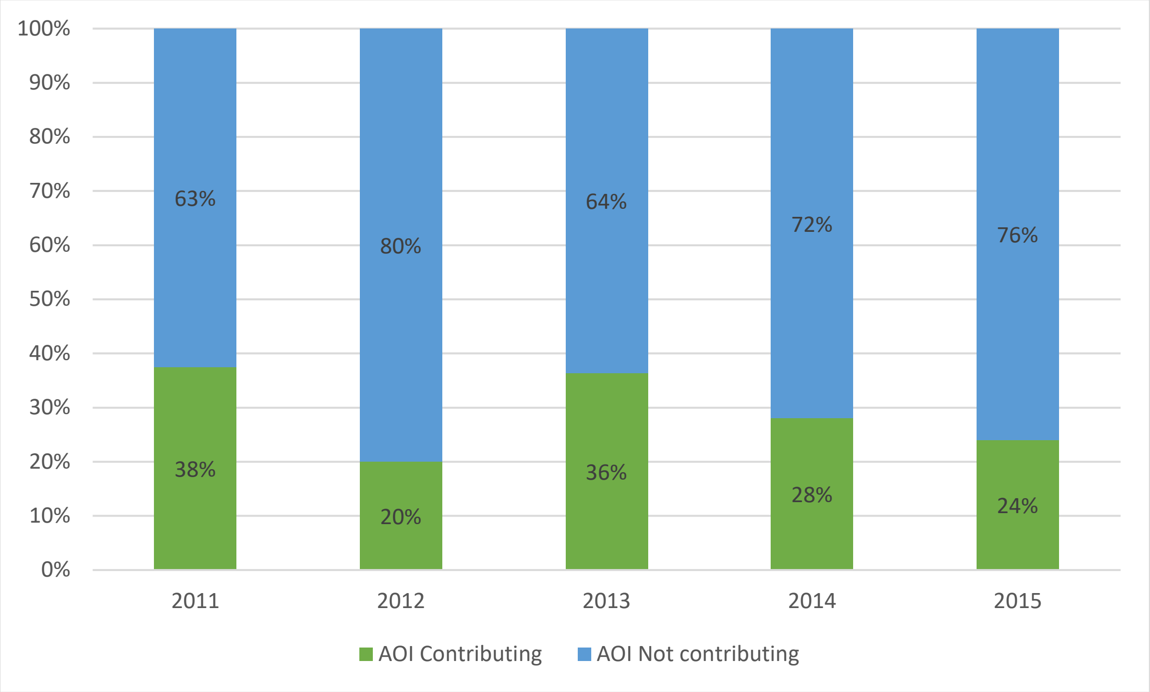

Figure A1 Proportion of "most impaired days" Iron Range AOI was Contributing or Not Contributing to Visibility at BWCA

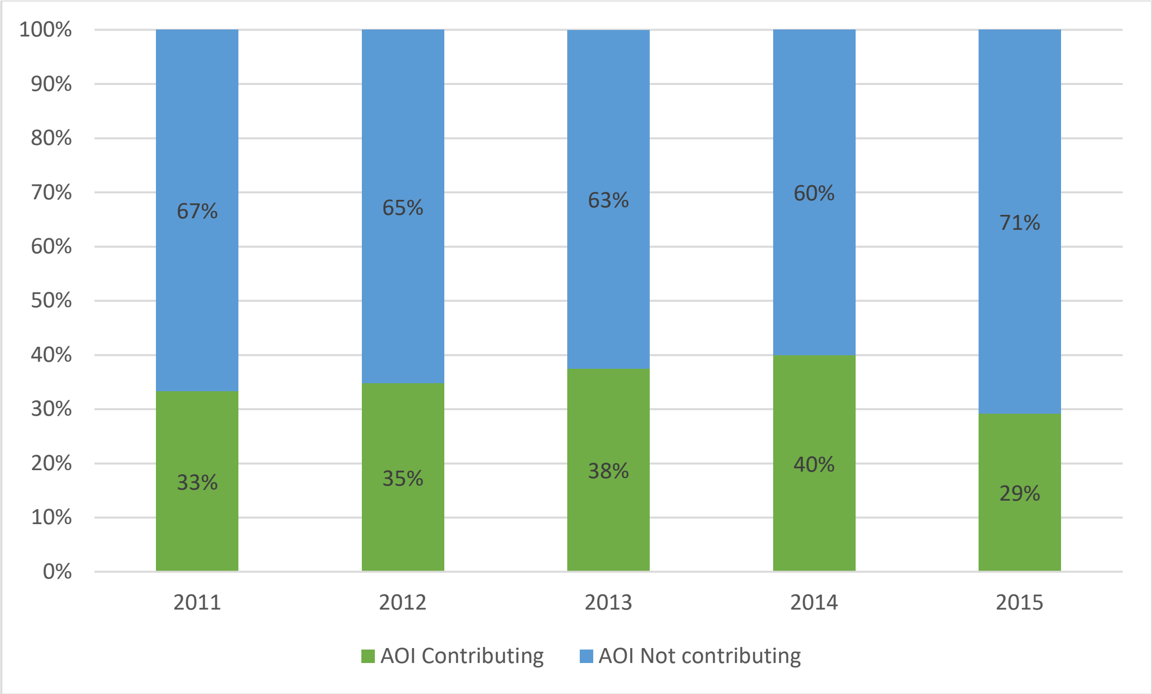

Figure A2 Proportion of "most impaired days" Iron Range AOI was Contributing or Not Contributing to Visibility at Voyageurs

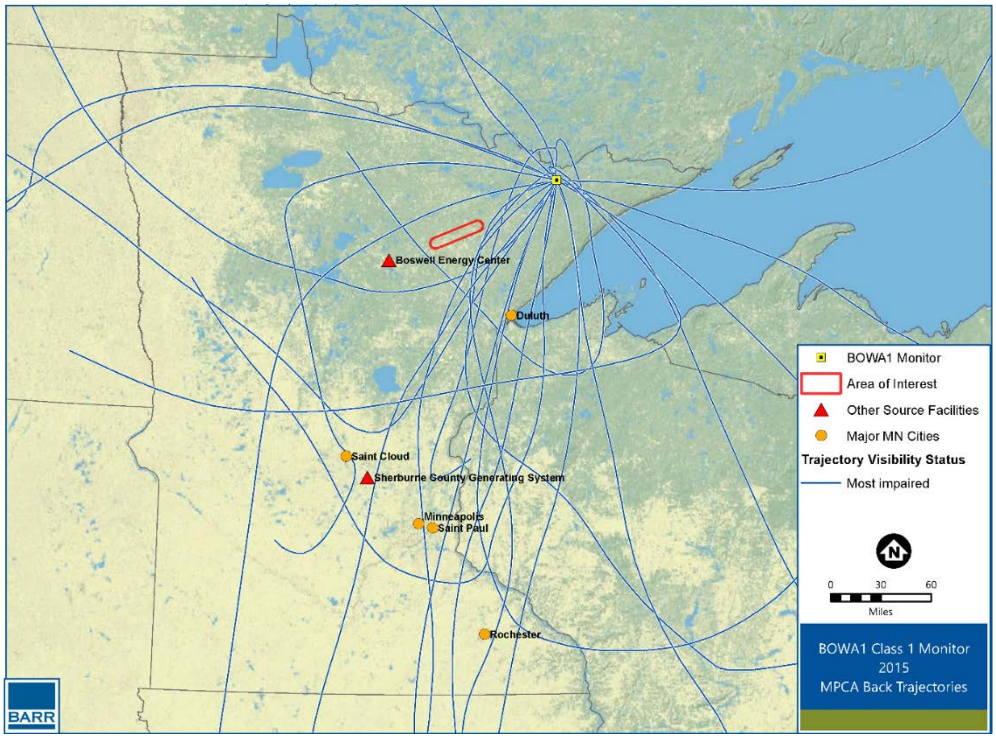

Figure A3 Reverse Trajectories and Other Sources Influencing Visibility at BWCA[9]

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[9] Source: ArcGIS 10.7.1, 2020-05-14 13:31 File: I:\Client\US_Steel\Trajectory_Analysis\Maps\Trajectory_Routes_BOWA1_2015_zoom.mxd User: ADS

A1.2 Photochemical Modeling

As part of the requirement to determine the sources to include and how to determine the potential visibility improvements to consider as part of this selection, the 2019 Guidance provided some specific guidance on the use of current and previous photochemical modeling analyses (emphasis added):

> *"A state opting to select a set of sources to analyze must reasonably choose factors and apply them in a reasonable way given the statutory requirement to make reasonable progress toward natural visibility. Factors could include but are not limited to baseline source emissions, baseline source visibility impacts (or a surrogate metric for the impacts), [and] the in-place emission control measures…"*[10]

The Guidance lists options for the evaluation of source visibility impacts from least rigorous to most rigorous as: (1) emissions divided by distance (Q/d), (2) trajectory analyses, (3) residence time analyses, and (4) photochemical modeling (zero-out and/or source apportionment). It appears that MPCA selected the least rigorous (Q/d) for inclusion of sources in the four-factor analyses. The most rigorous is described below (emphases added):

> ***"Photochemical modeling****. In addition to these non-modeling techniques, states can also use a photochemical model to quantify source or source sector visibility impacts. In 2017, EPA finalized revisions to 40 CFR Part 51 Appendix W, Guideline on Air Quality Models. As part of that action, EPA stated that photochemical grid models should be the generally preferred approach for estimating source impacts on secondary PM concentrations. The existing SIP Modeling Guidance provides recommendations on model setup, including selecting air quality models, meteorological modeling, episode selection, the size of the modeling domain, the grid size and number of vertical layers, and evaluating model performance. EPA Regional offices are available to provide an informal review of a modeling protocol before a state or multijurisdictional organization begins the modeling.*
>
> *The SIP Modeling Guidance focuses on the process for calculating RPGs using a photochemical grid model. The SIP Modeling Guidance does not specifically discuss using photochemical modeling outputs for estimating daily light extinction impacts for a single source or source sector. However, the approach on which the SIP Modeling Guidance is based can also be applied to a specific source or set of sources. The first step in doing this is to estimate the impact of the source or set of sources on daily concentrations of PM species.*
>
> *The simplest approach to quantifying daily PM species impacts with a photochemical grid model is to perform brute force "zero-out" model runs, which involves at least two model runs: one "baseline" run with all emissions and one run with emissions of the source(s) of interest removed from the baseline simulation. The difference between these simulations provides an estimate of the PM species impact of the emissions from the source(s).*

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[10] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, Page 10

> *An alternative approach to quantifying daily PM species impacts is photochemical source apportionment. Some photochemical models have been developed with a photochemical source apportionment capability, which tracks emissions from specific sources or groups of sources and/or source regions through chemical transformation, transport, and deposition processes to estimate the apportionment of predicted $PM_{2.5}$ species concentrations. Source apportionment can "tag" and track emissions sources by any combination of region and sector, or by individual source. For example, PM species impacts can be tracked from any particular source category in the U.S., or from individual states or counties. Individual point sources can also be tracked."*[11]

As part of the previous regional haze planning evaluation, and to provide comments on USEPA's disapproval of the Minnesota SIP and the subsequent Regional Haze Federal Implementation Plan (FIP) (Docket EPA-R05-OAR-2010-0954 & EPA-R05-OAR-2010-0037), Barr completed photochemical modeling of ArcelorMittal and Cleveland-Cliffs' taconite operations in 2013 using CAMx source apportionment (see Attachment 2). The basis of the CAMx modeling was the Minnesota modeling analyses, which were completed as part of the regional haze SIP, including Plume in Grid (PiG) evaluations of sources included in BART analyses. This modeling included 2002 and 2005 baseline periods with projected emissions to 2018 (the first implementation planning period for the regional haze SIPs and a strong surrogate for the baseline period for the 2nd planning period). Therefore, the analysis completed is one of the best available surrogates for the potential visibility impacts from the sources that were "tagged" as part of those comments. It is important to note that the MPCA modeling analysis did not require any additional controls for taconite sources under BART. Further, the CAMx modeling that Barr conducted showed that the impact from NO_X emissions from the Minnesota taconite facilities had very limited visibility impacts on the three Upper Midwest Class I areas.

Specifically, the results from executing CAMx concluded that the Class I areas near the Iron Range will not experience any observable visibility improvements from NO_X emission reductions that were suggested by the USEPA in the final Regional Haze FIP for taconite indurating furnaces. The modeling analysis showed that the scalar method that USEPA used to forecast the visibility improvements was inadequate to determine the visibility impacts from taconite sources. The CAMx predicted impacts for every furnace line were at or below the de minimis threshold for visibility improvement (0.1 delta-dV).

In addition, the large amount of potential NO_X emission reductions from the FIP baseline to the final FIP (>10,000 tons per year from modeled Minnesota taconite operations) was not impactful from a visibility modeling perspective. This finding provides specific source modeling evidence that additional NOx emission reductions from any or all of the taconite operations are likely not helpful for visibility improvements at the Upper Midwest Class I areas. This is particularly true given the current amount of NO_X emissions generated by the taconite sources as part of the current baseline.

The 2019 Guidance addresses how states should select sources that must conduct a four-factor analysis. The RHR suggests that states can use a photochemical model to quantify facility or even stack visibility impacts. The previous CAMx modeling was conducted for the 2018 projection year and the results are

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[11] Ibid, Page 14.

especially helpful in the current visibility impact assessment to determine if the EPA's four-factor applicability analysis is necessary. Aside from the fact that the NO_X reductions of taconite indurating furnaces do not result in visibility improvements, the emissions from these sources have been trending downward from 2013 to present. These reductions are related to the recent installation of low NO_X burners on the taconite indurating furnaces and the overall Minnesota state reductions from the switch from coal- to natural gas-fired power plants. Thus, it is reasonable to conclude that additional emission reductions beyond the FIP limits of the taconite indurating furnaces will not be beneficial to improve visibility at the Class 1 areas nor is it anticipated to be necessary to reach the 2028 target visibility goal.

In summary, the exclusion of the taconite sources from the four factor analysis for NOx is reasonable, supported by the previous CAMx modeling performed for 2018 projected emissions that conclude additional emission reductions beyond the FIP limits of the taconite indurating furnaces will not be beneficial to improve visibility, and in line with the Guidance regarding selection of sources based on previous modeling analyses and the additional NO_X reductions anticipated in Minnesota.

A1.3 Visibility Impacts During 2009 Recession

During the economic recession in 2009, the Iron Range experienced a reduction in taconite production. This resulted in a decrease in emissions from the collective group of taconite plants and the regional power production that is needed to operate the plants. The IMPROVE monitoring data during this period was compared to monitoring data during more typical production at the taconite plants to estimate the actual (rather than modeled) impact on haze. This assessment was completed in 2012 (herein termed as "the 2012 analysis") and submitted by Cliffs as a comment to proposed Minnesota regional haze requirements (Docket: EPA-R05-OAR-2010-0037), included as Attachment 3. The 2012 analysis focused on the likely visibility impact of NO_X emissions from the taconite indurating furnaces.

Observations noted in the 2012 analysis highlighted that concentrations of visibility impairing pollutants do not appear to closely track with actual emissions from taconite facilities. For example, nitrate (NO_3) is a component of haze associated with NO_X emissions that are emitted from a number of sources, including the indurating furnaces at the taconite facilities. As shown in Figure A4, the 2012 analysis compared taconite facility production rates to nitrate concentration for 1994-2010 at the BWCA monitor. The 2012 analysis concludes that "haze levels in BWCA did not, in general, decrease during 2009, and were therefore unaffected by emission reductions associated with the taconite production slowdown. It is noteworthy that peak events during mid-2009 in sulfate haze at BWCA when very little taconite production was occurring clearly indicate that minimal haze reduction would likely be associated with taconite plant emission reductions."[12] The report further notes that "high nitrate haze days late in 2009 with the taconite plant curtailment that are comparable in magnitude to full taconite production periods in 2008. We also note that after the taconite plants went back to full production in 2010, the haze levels dropped, apparently due to emissions from other sources and/or states."[13]

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[12] AECOM, "Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas," 09/28/2012, Page 10.

[13] Ibid, Page 12.

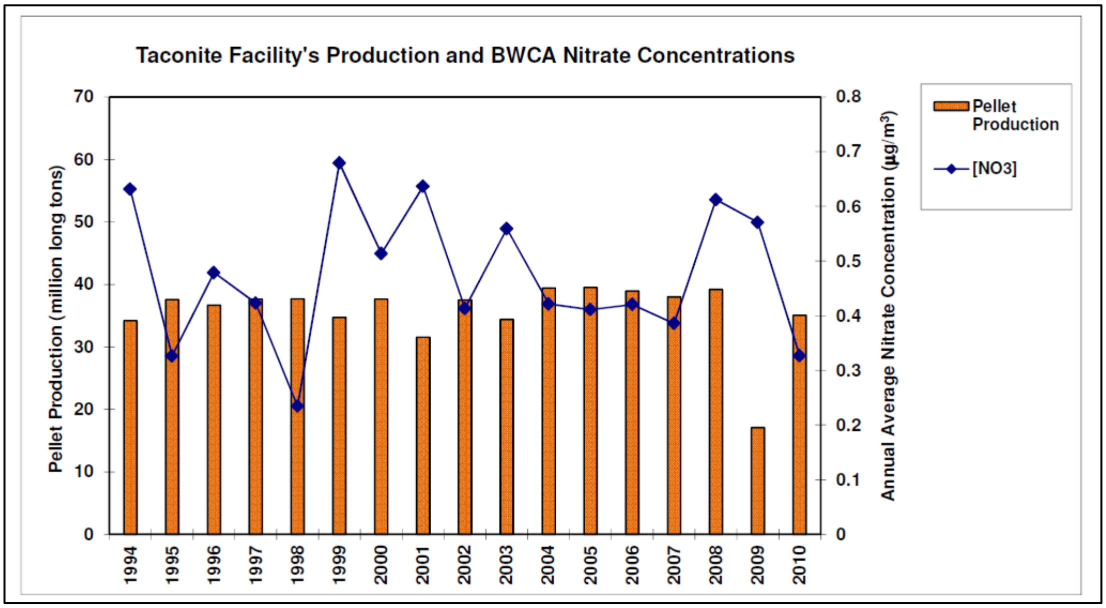

Figure A4 Minnesota Taconite Production and BWCA Nitrate Concentrations 1994-2010 [14]

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[14] AECOM, "Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas," 09/28/2012, Page 9

Attachments

Attachment 1

Trajectory Analysis Summary Tables and Reverse Trajectory Example Figures

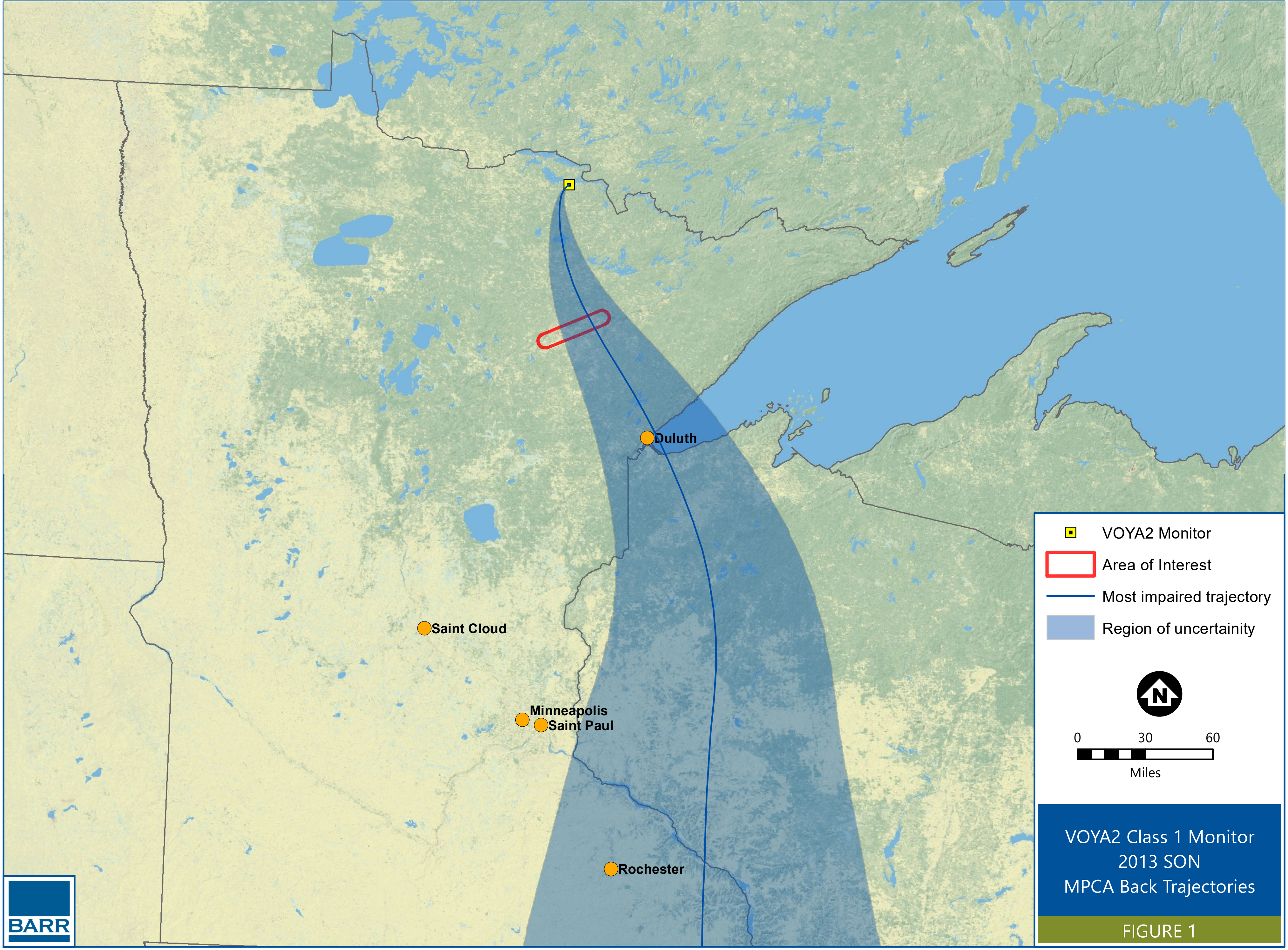
Table A1 Results from MPCA Hysplit Trajectories for the BOWA1 Monitor

Year	Time Period	Most Impaired Days	"Most Impaired" Trajectories With Uncertainty Region Crossing Iron Range AOI (%)
2011	Winter (DJF)	9	44%
	Spring (MAM)	8	38%
	Summer (JJA)	4	0%
	Fall (SON)	3	67%
	Total	**24**	**38%**
2012	Winter (DJF)	13	23%
	Spring (MAM)	4	0%
	Summer (JJA)	1	0%
	Fall (SON)	7	29%
	Total	**25**	**20%**
2013	Winter (DJF)	9	44%
	Spring (MAM)	5	60%
	Summer (JJA)	3	0%
	Fall (SON)	5	20%
	Total	**22**	**36%**
2014	Winter (DJF)	9	33%
	Spring (MAM)	8	13%
	Summer (JJA)	2	0%
	Fall (SON)	6	50%
	Total	**25**	**28%**
2015	Winter (DJF)	13	15%
	Spring (MAM)	3	67%
	Summer (JJA)	1	0%
	Fall (SON)	8	25%
	Total	**25**	**24%**

Table A2 Results from MPCA Hysplit Trajectories for the VOYA2 Monitor

Year	Months	Most Impaired Days	"Most Impaired" Trajectories With Uncertainty Region Crossing Iron Range AOI (%)
2011	Winter (DJF)	8	38%
	Spring (MAM)	7	29%
	Summer (JJA)	4	25%
	Fall (SON)	5	40%
	Total	**24**	**33%**
2012	Winter (DJF)	13	23%
	Spring (MAM)	3	67%
	Summer (JJA)	0	0%
	Fall (SON)	7	43%
	Total	**23**	**35%**
2013	Winter (DJF)	9	22%
	Spring (MAM)	5	40%
	Summer (JJA)	3	0%
	Fall (SON)	7	71%
	Total	**24**	**38%**
2014	Winter (DJF)	10	50%
	Spring (MAM)	7	43%
	Summer (JJA)	2	0%
	Fall (SON)	6	33%
	Total	**25**	**40%**
2015	Winter (DJF)	14	21%
	Spring (MAM)	4	50%
	Summer (JJA)	1	100%
	Fall (SON)	5	20%
	Total	**24**	**29%**

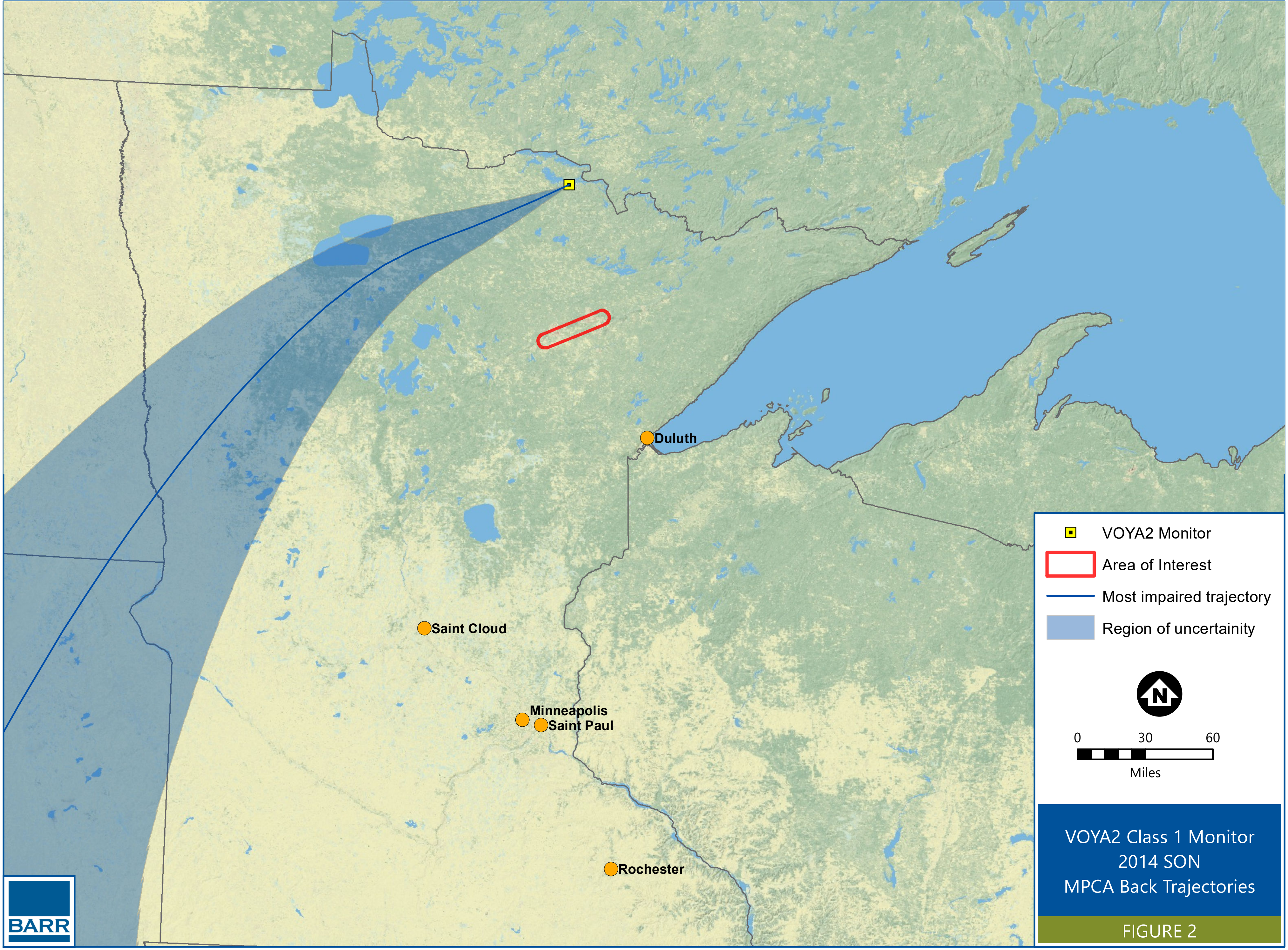
Barr Footer: ArcGIS 10.7.1, 2020-05-15 13:43 File: I:\Client\US_Steel\Trajectory_Analysis\Maps\Trajectory_Analysis_VOYA2_2013_SON.mxd User: ADS



VOYA2 Class 1 Monitor
2013 SON
MPCA Back Trajectories

FIGURE 1

Barr Footer: ArcGIS 10.7.1, 2020-05-15 13:43 File: I:\Client\US_Steel\Trajectory_Analysis\Maps\Trajectory_Analysis_VOYA2_2013_SON.mxd User: ADS



VOYA2 Class 1 Monitor
2014 SON
MPCA Back Trajectories

FIGURE 2

Attachment 2

CAM_X Modeling Report

resourceful. naturally.
engineering and environmental consultants
BARR

Technical Memorandum

From: Barr Engineering
Subject: Summary of Comprehensive Air Quality Model with Extensions (CAM_X) Analyses Performed to Evaluate the EPA Regional Haze Federal Implementation Plan for Taconite Facilities
Date: March 6, 2013

Executive Summary

Barr Engineering conducted air modeling to predict the impact of NO_X reductions from certain taconite furnaces in Minnesota and Michigan. Using EPA's preferred Comprehensive Air Quality Model with Extensions (CAM_X), the model results demonstrate that the Class I areas near these furnaces will experience no perceptible visibility improvements from NO_X emission reductions envisioned by EPA in the recent Regional Haze FIP at the furnaces. The analysis strongly suggests that the scalar method that EPA used to predict visibility improvements under significant time constraints was an inadequate substitute for CAM_X, as EPA's approach over-predicted visibility impacts by factors of ten to sixty when compared with the proper CAM_X analysis. The basis for EPA's technical analysis of the visibility improvements for their proposed emission changes must therefore be dismissed as unsupportable, and the results of this analysis should be used instead. This analysis ultimately supports the conclusions of the States of Michigan and Minnesota in their Regional Haze SIPs, that experimental low NO_X burner retrofits did not meet the criteria for BART. The imperceptible visibility improvements associated with NO_X reductions from these furnaces cannot justify the cost or the operational risks of changing burners.

Discussion

This memorandum provides a summary of the methodology and results from photochemical modeling analyses conducted to support the Cliffs Natural Resources (CNR) and Arcelor Mittal (Arcelor) response to the United States Environmental Protection Agency (EPA) final Regional Haze Federal Implementation Plan (FIP) for taconite facilities. Further, it provides a basis for comment on the proposed disapproval of the Minnesota and Michigan State Implementation Plans for taconite Best Available Retrofit Technology (BART) at the above mentioned facilities. This memorandum also includes an appendix with a summary of the BART visibility improvement requirements and a review of

the EPA “scalar” method in the proposed and final FIP for determining the visibility improvement from taconite emission reductions. Further, the memorandum contrasts EPA’s findings with the modeling analysis conducted and previously requested by CNR as part of its comments on the proposed FIP. The modeling evaluated emission differences at all the CNR and Arcelor taconite facilities.

Ultimately, this memorandum provides results demonstrating no perceptible visibility improvement from the NO_X emission reductions proposed and subsequently finalized by EPA in the Regional Haze FIP for the CNR and Arcelor facilities.

I. CAM_X Modeling Methodology

The methodology utilized by Barr to complete the CAM_X modeling was identical to the methods utilized by the Minnesota Pollution Control Agency (MPCA) in performing the 2002 and 2005 baseline and BART SIP modeling in 2009. This included the use of the CAM_X modeling system (CAM_X v5.01 - air quality model, MM5 - meteorological model, and EMS-2003 - emissions model) with meteorological data, low-level emission data, initial and boundary condition files, and other input files received directly from MPCA. Modifications to the emissions within the elevated point source input files used by MPCA were accomplished for the taconite facility furnace stacks to reflect the differences in the FIP baseline and final FIP control scenarios. In addition, the CAM_X run scripts used to execute the model were provided by MPCA for each of the four calendar quarters (Jan-Mar, Apr-Jun, Jul-Sep, and Oct-Dec) along with the post-processing scripts used to estimate the visibility impacts for each scenario.

An important fact is that the results from the MPCA modeling for Minnesota’s regional haze State Implementation Plan (SIP) development were also utilized by EPA in the “scalar” method proposed in the FIP. These results were subsequently defended by EPA in the final FIP stating “EPA stands by the results of its ratio approach and believes that it produced reasonable results for the sources examined.”[1] The methods utilized by MPCA represent not only an EPA-approved approach for SIP submittal, but also formed the basis of the visibility determinations made by EPA in the proposed and final FIP. However, since EPA did not conduct its own modeling and provided only the “scalar” results, there are substantial and inherent flaws in the EPA-estimated visibility impacts. These flaws are detailed in Appendix A to this memorandum which includes a review of the EPA scalar approach. Since the modeling reported here used identical methods to the MPCA analyses, it is consistent with the underlying data that was used in

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[1] Federal Register, Volume 78, Number 25, page 8721, February 6, 2013

the EPA FIP method for estimating visibility impact. Further, this modeling provides specific technical analyses regarding the estimated effects of CNR and Arcelor taconite unit emission reductions in the final FIP on the relevant Class I areas. To effectively evaluate the impact of NOx reductions on regional haze, this level of analyses should have been conducted by EPA before publishing and finalizing the taconite BART FIP for Minnesota and Michigan.

Nonetheless, the first step in any photochemical modeling exercise is to ensure that the modeling results can be replicated to ensure no errors in the data transfer or modeling setup. Barr worked with MPCA to obtain the 2002 and 2005 modeling input files, run scripts, and post-processing files to allow for the validation of the Barr modeling system. To be clear, the modeling comparison scenario used the exact same files provided by MPCA with no adjustments. Given the length of time required to complete the modeling analyses, this step focused on the 2002 dataset and evaluated the results from the 2002 baseline and 2002 Minnesota BART SIP. The information provided by MPCA to complete this comparison was contained in the document: "Visibility Improvement Analysis of Controls Implemented due to BART Determinations on Emission Units Subject-to-BART", October 23, 2009. The results of the comparison are contained in Appendix B: Barr and MPCA CAM_X Modeling Comparison of Results. As expected with any photochemical model comparison running four different quarterly simulations using two different computer systems and Fortran compilers, there are insignificant differences in the end values. The overall comparison of the results was very favorable and showed excellent agreement between the four modeled datasets (i.e. 2002 baseline and 2002 BART SIP, each from MPCA and Barr).

After successful confirmation of the consistency check of the Barr modeling system to the MPCA system, the modeling focused on the specific emission changes in the MPCA elevated point source files. As with most regional modeling applications, there were 36 "core" point source files for each scenario. This set corresponds to three files per month (Saturday, Sunday, and weekday) for all twelve months. Emission information from each file was extracted for all the CNR and Arcelor taconite facilities in Minnesota to confirm the emission totals used by MPCA in the SIP baseline and BART SIP control scenarios. The emission summary data for each unit matched the summary tables within the MPCA BART SIP modeling. Also, the emission sources from Tilden Mining Company in Michigan were identified and information extracted to allow for the same type of modeling as was conducted for the Minnesota facilities.

The next step was to include United Taconite Line 1 in the baseline and FIP modeling files. Line 1 was not originally included in the MPCA modeling because it was not operational in the 2002 base year.

Therefore, the information for that source was obtained from MPCA-provided 2018 elevated point source files and incorporated into the 36 core elevated point source files. This allowed all the CNR and Arcelor furnace lines within the FIP to be evaluated as part of this modeling analysis. To that end, each CNR and Arcelor BART-eligible source was specifically identified and labeled for processing to track modeled impacts using plume-in-grid treatment and the Particulate Source Apportionment Technology (PSAT) contained within CAM_X (including Tilden Mining). A list of the sources that were included in the specific PSAT groups can be found in Appendix C: CAM_X PSAT Source List.

As part of the identification and labeling process, the MPCA BART SIP elevated point source files were converted from binary input files to ascii text files using the BIN2ASC program. (NOTE: by using the BART SIP point source files, all other Minnesota BART-eligible sources were included in this modeling exercise using their BART SIP emissions to isolate the impacts of the CNR and Arcelor units.) Then, a Fortran90 program was developed to adjust the hourly emissions from each applicable source to correspond to the sum of annual emissions within each of the following scenarios: EPA FIP baseline and EPA final FIP. It is important to note that the temporal factors for each source were not modified from the original MPCA-provided inventory files (i.e. no changes to the monthly or day-of-week factors). This emission approach allowed for the exact set of emissions within each of the scenarios to be modeled. After the emissions within the text file were adjusted, the emissions were checked for accuracy. Then, each file was converted back to binary input from ASCII text using the ASC2BIN program. The emission summary for each unit/scenario combination is contained in Appendix D: Summary of CAM_X Elevated Point Source Emissions. Appendix D also provides a reference list for the emissions from the proposed FIP, Final FIP (where applicable), and calculation methodology where EPA did not provide sufficient information to calculate emissions. Table 1 contains a facility summary for all taconite furnaces under each scenario.

As stated previously, one of the outcomes of these analyses was the comparison of EPA's scalar approach to specific photochemical modeling using EPA's emission reduction assumptions within the FIP rulemakings. These modeling analyses make no judgment as to the achievability of these emission reductions. CNR and Arcelor dispute that these NOx reductions are achievable for all furnaces. These modeling analyses are, therefore, a conservative evaluation of EPA's predicted NOx reductions – not the actual NOx reductions achievable by the application of BART.

Table 1: Facility Taconite Furnace Emission Summary

Facility	FIP Baseline (TPY)		Final FIP (TPY)		Difference (TPY)	
	SO2	NOx	SO2	NOx	SO2	NOx
Arcelor Mittal	179	3,639	179	1,092	0	2,547
Hibbing Taconite	570	6,888	570	2,066	0	4,821
United Taconite	4,043	5,330	1,969	1,599	2,074	3,731
Northshore Mining	73	764	73	229	0	535
Tilden Mining	1,153	4,613	231	1,384	922	3,229
Total	**6,018**	**21,233**	**3,022**	**6,370**	**2,996**	**14,863**

Two other issues should be noted here.

1. The first is the nested 12-km modeling domain selected by MPCA (illustrated in Figure 1) along with the specific "receptors" used for identification of the relevant Isle Royale Class I area and their use for determination of impacts from Tilden Mining Company. The Tilden Mining source was not included in the MPCA fine grid as it was not part of the Minnesota SIP. However, the elevated point source file includes the sources in the entire 36 km domain (including Tilden). As such, the Tilden emissions were available for estimation of specific visibility impacts. The receptors selected by MPCA only included the western half of the Isle Royale Class I area because that is the portion of the area closest to the Minnesota sources. However, the size of the grid cells (e.g. 12 and 36 km) provides a large number of potential receptors at all the Class I areas and little variation among receptors is expected at the distance between Tilden and Isle Royale. Thus, the modeling data should adequately represent the visibility impact at the entire Isle Royale Class I area.

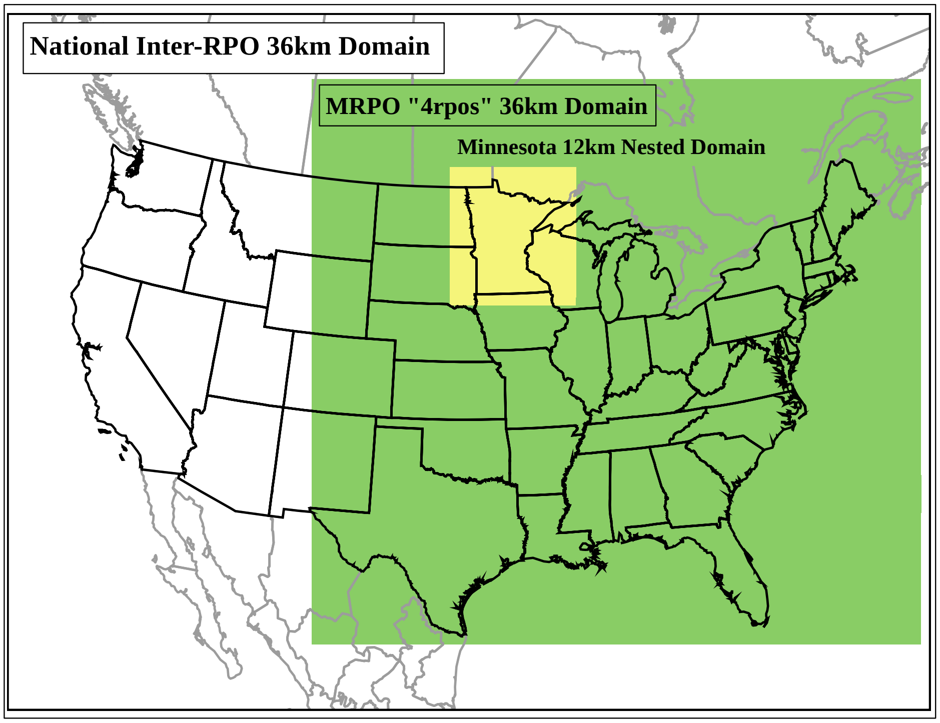

Figure 1. MPCA Modeling Domain

2. The second issue is the inconsistency between the emission reduction estimates used by EPA in the calculation of their scalar visibility benefits (i.e. Tables V-C of the proposed and final FIP) and the emission reductions calculated in the facility-specific sections of the proposed FIP. EPA's flawed calculation methodology did not use the appropriate emission reductions. In order to calculate the emissions for evaluation of the final FIP in the CAM_X modeling, Barr was left with utilizing the limited information provided in the proposed and final FIP rulemaking. The lack of information and the errors and inconsistencies within the dataset were highlighted in the information request on January 31, 2013 to EPA (included in Appendix E). As of the time of this memorandum, no response by EPA has been received by Barr. Further, given the time required to complete the modeling, assumptions were made that were conservative to calculate the FIP emissions. For example, the final FIP references a 65% NO_X reduction from Tilden Mining Company due to the switch to natural gas firing, but that was not consistent with the other gas-fired kilns (proposed FIP reduction was 70% with the same 1.2 lb NO_X/MMBTU emission limit). Therefore, to provide the maximum emission reductions, the 70% control was utilized for all the CNR and Arcelor taconite furnaces.

II. Summary of CAM_X Results

As mentioned above, the CAM_X model was executed for each calendar quarter of 2002 and 2005 using the adjusted emissions for each scenario. The results were then post-processed to calculate visibility impacts for each scenario in deciviews (dV). All these results are provided in Appendix F: CAM_X Results by Facility. For the purposes of this memorandum, the following tables compare EPA's estimates of annual average impact contained within the proposed FIP with the results generated by the CAM_X modeling for this project on a facility by facility basis. The first three facilities contain emission reductions for only NO_X: Arcelor Mittal, Hibbing Taconite, and Northshore Mining. These results are summarized in Tables 2-4. United Taconite and Tilden Mining, which have both SO_2 and NO_X emission reductions, have result comparisons that require additional discussion.

The context of these results includes the following visibility impact thresholds:

0.5 dV impact is the BART eligibility and contribute to visibility impairment threshold (i.e. if a facility has less than 0.5 dV impact in the baseline, no BART is required)[2],

1.0 dV difference is the presumed human perceptible level for visibility improvement, and

0.1 dV difference was defined by other agencies, such as the northeastern states MANE-VU Regional Planning Organization[3] as the degree of visibility improvement that is too low to justify additional emission controls. In addition, EPA's Regional Haze Rule mentions[4] that "no degradation" to visibility would be "defined as less than a 0.1 deciview increase."

The first two columns within Tables 2-4 and 6-8 provide the difference in 98th percentile visibility improvement from the baseline to the FIP control emissions, while the third column provides a measure of over-estimation when using the EPA scalar approach (i.e. % Over Estimation by EPA = EPA Estimated Difference / CAM_X Modeled Difference).

Table 2: Arcelor Mittal Visibility Impact Comparison

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[2] 40 CFR Part 51, Appendix Y – Guidelines for BART Determinations under the Regional Haze Rule.

[3] As documented by various states; see, for example, www.mass.gov/dep/air/priorities/hazebart.doc, which indicates a visibility impact of less than 0.1 delta-dv is considered "de minimis".

[4] 64 FR 35730.

Class I Area	EPA Estimated Difference 98% dV		CAM$_X$ Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	1.7		0.1		1500%
Voyageurs	0.9		0.09		1000%
Isle Royale	1.1		0.03		3700%

Table 3: Hibbing Taconite Visibility Impact Comparison

Class I Area	EPA Estimated Difference 98% dV		CAM$_X$ Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	3.2		0.19		1700%
Voyageurs	1.7		0.11		1500%
Isle Royale	2.1		0.04		5300%

Table 4: Northshore Mining Visibility Impact Comparison

Class I Area	EPA Estimated Difference 98% dV		CAM$_X$ Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	0.6		0.01		6000%
Voyageurs	0.3		0.01		3000%
Isle Royale	0.4		0.01		4000%

As pointed out in the previous comments on this proposed FIP, these results clearly demonstrate that the NOx reductions proposed in the FIP will not provide a perceptible visibility improvement. Additionally, it demonstrates that the EPA methodology using scalars severely overestimated the visibility impact from NO_X emission reductions at these taconite furnaces in northeast Minnesota. Even when using maximum emission reductions from EPA's baseline, the EPA estimates grossly over predicted the potential dV improvement by over 10 times the predicted 98th percentile visibility improvement in all cases for the Arcelor Mittal, Hibbing Taconite, and Northshore Mining facilities. The maximum 98th percentile visibility improvement predicted by the source specific tracking for any one line was 0.1 dV (Arcelor Mittal Line 1 on Boundary Waters). The minimum 98th percentile visibility improvement was 0.01 dV (Northshore Mining on Isle Royale). Further, the results presented in Table 5 for the individual furnace line impacts at Hibbing Taconite illustrate de minimis visibility improvement at all the Class I areas evaluated.

Table 5: Hibbing Taconite Line-Specific Visibility Impacts

Class I Area	Furnace Line		CAM_X Modeled Difference 98% dV
Boundary Waters	Line 1		0.04
	Line 2		0.05
	Line 3		0.08
Voyageurs	Line 1		0.03
	Line 2		0.04
	Line 3		0.04
Isle Royale	Line 1		0.01
	Line 2		0.01
	Line 3		0.01

Overall, all the facilities with only NO_X emission reductions predict visibility improvement from each furnace line at or below the de minimis visibility improvement threshold of 0.1 delta-dV.

Due to the sizable change in the United Taconite SO_2 emission reductions from the proposed FIP to the final FIP; the visibility improvement was re-calculated using EPA's apparent methodology from the proposed FIP. The EPA scalars (proposed FIP – Table V – C.9) were applied for each pollutant using the corrected emission reduction for NO_X and the revised emission reduction for SO_2. Then, those resultants were averaged for each of the Class I areas to obtain the "updated" EPA all pollutant estimates.

Table 6: United Taconite Visibility Impact Comparison (All Pollutants)

Class I Area	Amended EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	1.6		1.40		110%
Voyageurs	0.8		0.85		N/A
Isle Royale	1.1		0.35		320%

The comparison of the total modeling effort including both pollutant reductions is surprisingly similar (except for Isle Royale). However, when the individual pollutant impacts are examined, the problem with EPA's methodology is more clearly understood. The sulfate impacts are estimated more closely to the CAM_X results, while the nitrate impacts are grossly overestimated similar to the first three facilities.

The methodology used to isolate the sulfate and nitrate impacts separately from the current CAM$_X$ results prioritizes the sulfate and nitrate impacts as part of three separate post-processing runs (all pollutants, sulfate, and nitrate). The sulfate impact was derived by sorting the visibility impacts at each receptor from each scenario by maximum sulfate contribution for each line. Likewise, the nitrate impact was derived by sorting the visibility impacts at each receptor from each scenario by maximum nitrate contribution for each line. Then, the results were summed for both lines to obtain the overall United Taconite impact by pollutant. In nearly all circumstances, this will overestimate the impact of the NO$_X$ control. This is due to the impact from the sulfate reductions that drives the total visibility impact with a much smaller percentage from the nitrate reductions. When the nitrate impact is maximized by the sorting technique, the overall impact on the same day could be very small (e.g. nitrate = 0.1 dV; total = 0.15 dV) and would not show up as part of the overall visibility change. As detailed in the comments to the proposed FIP, it is also important to note the high probability that the maximum impacts from NO$_X$ emission reduction occur during the winter months when Isle Royale is closed to visitors and visitation at the other Class I areas is significantly reduced from summertime maximum conditions.[5]

Table 7: United Taconite Visibility Impact Comparison (Sulfate Impact)

Class I Area	Amended EPA Estimated Difference 98% dV		CAM$_X$ Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	1.0		1.29		N/A
Voyageurs	0.5		0.74		N/A
Isle Royale	0.6		0.28		210%

Table 8: United Taconite Visibility Impact Comparison (Nitrate Impact)

Class I Area	Amended EPA Estimated Difference 98% dV		CAM$_X$ Modeled Difference 98% dV		% Over Estimation by EPA
Boundary Waters	2.3		0.18		1300%
Voyageurs	1.1		0.08		1400%
Isle Royale	1.6		0.05		3200%

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[5] Cliffs Natural Resources (September 28, 2012), EPA-R05-OAR-0037-0045 Att. M

In the same manner as Hibbing Taconite, United Taconite's individual furnace lines were evaluated. As mentioned in the previous paragraph, the results in Table 9 for nitrate impact are biased toward higher nitrate impacts due to the sorting of the data to maximize nitrate impact.

Table 9: United Taconite Line-Specific Nitrate Visibility Impacts

Class I Area	Furnace Line		CAM_X Modeled Difference 98% dV
Boundary Waters	Line 1		0.05
	Line 2		0.1
Voyageurs	Line 1		0.02
	Line 2		0.06
Isle Royale	Line 1		0.02
	Line 2		0.03

Nonetheless, as seen for all the other furnace lines, the results for United Taconite's predicted visibility impact are at or below the deminimis threshold for visibility improvement.

Since Tilden Mining Company was not evaluated using the same methodology as the Minnesota taconite facilities, there are no specific EPA data to compare with the CAM_X results. However, it is important to understand that the results are very similar to the other results regarding the impact of NO_X emission reductions on these Class I areas.

Table 10: Tilden Mining Visibility Impact Comparison (All Pollutants)

Class I Area	EPA Estimated Difference 98% dV		CAM_X Modeled Difference 98% dV
Boundary Waters	N/A		0.08
Voyageurs	N/A		0.03
Isle Royale	N/A*		0.17

*EPA estimated that the proposed FIP results in 0.501 dV visibility improvement at Isle Royale from emission reduction at Tilden Mining

Table 11: Tilden Mining Pollutant-Specific Impact Comparison

Class I Area	CAM_X Sulfate Modeled Difference 98% dV		CAM_X Nitrate Modeled Difference 98% dV
Boundary Waters	0.07		0.01
Voyageurs	0.03		0.00
Isle Royale	0.14		0.02

The visibility impacts from NO_X emission reductions at Tilden are consistent with the other modeling results and further demonstrate that significant emission reductions of NOx (3,229 tpy for Tilden) result in no visibility improvements.

III. Conclusions

Overall, the results from the three facilities with only NO_X emission reductions (Hibbing Taconite, Northshore Mining, and Arcelor Mittal) and the pollutant-specific comparisons for United Taconite and Tilden Mining illustrate that nearly 15,000 tons per year of NO_X reductions, even if they were technically and/or economically achievable, provide imperceptible visibility impacts at the Minnesota or nearby Michigan Class I areas. In all cases, the CAMx-predicted impacts for every furnace line are at or below the de minimis threshold for visibility improvement (0.1 delta-dV).

The fact that NO_X emission reductions do not provide perceptible visibility improvement was understood by MPCA when they proposed existing control and good combustion practices as BART for taconite furnaces in northeast Minnesota. This finding has been confirmed by this detailed modeling analysis. EPA, to its credit, does not claim that its scalar "ratio" approach for predicting visibility improvement is accurate. In the final FIP, EPA provided, "Therefore, even if the ratio approach was over-estimating visibility improvement by a factor of two or three, the expected benefits would still be significant."[6] Our analysis demonstrates that the ratio approach has over-estimated impacts by a factor of ten to sixty for NO_X reductions. When accurately modeled, the NO_X reductions do not yield discernible visibility benefits. To that end, the following pictures from WinHaze Level 1 Visual Air Quality Imaging Modeler

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[6] Federal Register, Volume 78, Number 25, page 8720, February 6, 2013

(version 2.9.9.1) provide a visual reference for the CAM_X predicted visibility impairment from the maximum nitrate impacting facility at Isle Royale and Boundary Waters[7].

Isle Royale FIP Base – United Taconite

Isle Royale Final FIP – United Taconite

Boundary Waters FIP Base – Hibbing Taconite

Boundary Waters Final FIP – Hibbing Taconite

Given the size of the predicted visibility impacts (both less than 0.2 dV improvement), these pictures illustrate no discernible visibility improvement from NO_X reductions at either Class I area.

Ultimately, Minnesota and Michigan reached their visibility assessments in different ways, but this modeled analysis supports their conclusion that low NO_X burner technology is not BART for the furnaces modeled at Arcelor Mittal - Minorca, Hibbing Taconite, Northshore Mining Company, United Taconite, and Tilden Mining. Therefore, EPA should approve the sections of the SIPs establishing NO_X BART on this basis.

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[7] Voyageurs National Park pictures are not contained within the WinHaze program

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APPENDIX A: Visibility Impact Requirements and EPA's Scalar Approach for Estimating Visibility Impacts within the Taconite FIP

March 6, 2013

I. Summary of Visibility Impact Requirements

The relevant language related to the specific BART visibility impact modeling approach from 40 CFR 51 Appendix Y (herein, Appendix Y), *Guidelines for BART Determinations Under the Regional Haze Rule,* is provided here, in italics with some language underlined for emphasis:

5. Step 5: How should I determine visibility impacts in the BART determination?

- *For each source, run the model, at pre-control and post-control emission rates according to the accepted methodology in the protocol.*

Use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled (for the pre-control scenario). Calculate the model results for each receptor as the change in deciviews compared against natural visibility conditions. Post-control emission rates are calculated as a percentage of pre-control emission rates. For example, if the 24-hr pre-control emission rate is 100 lb/hr of SO[2], then the post control rate is 5 lb/hr if the control efficiency being evaluated is 95 percent.

- *Make the net visibility improvement determination.*

Assess the visibility improvement based on the modeled change in visibility impacts for the pre-control and post-control emission scenarios. You have flexibility to assess visibility improvements due to BART controls by one or more methods. You may consider the frequency, magnitude, and duration components of impairment. Suggestions for making the determination are:

  - *Use of a comparison threshold, as is done for determining if BART-eligible sources should be subject to a BART determination. Comparison thresholds can be used in a number of ways in evaluating visibility improvement (e.g., the number of days or hours that the threshold was exceeded, a single threshold for determining whether a change in impacts is significant, or a threshold representing an x percent change in improvement).*
  - *Compare the 98th percent days for the pre- and post-control runs.*

Note that each of the modeling options may be supplemented with source apportionment data or source apportionment modeling.

It should be noted that Appendix Y is a guideline for state air quality agencies to proceed with modeling of BART sources. Therefore, these are not requirements, but recommended practices for evaluation of visibility impacts. Significant discretion was given to each state regarding the use of these methods. To that end, the Minnesota Pollution Control Agency applied a different modeling system than the EPA-approved model (CALPUFF) for BART evaluations. Discussed below, the new modeling system was subsequently used by EPA as part of their FIP proposal.

Further, an excerpt from the Clean Air Act, Part C, Subpart II is provided below to establish the basis for the Appendix Y regulations related to visibility improvement.

II. Summary of EPA's approach

Specific language from the proposed and final FIPs are provided in *italics* along with comments.

EPA relied on visibility improvement modeling conducted by the Minnesota Pollution Control Agency (MPCA) and recorded in MPCA's document "Visibility Improvement Analysis of Controls Due to BART Determinations on Emission Unit's Subject to BART", October 23, 2009 [attached]. The visibility improvement modeling conducted by MPCA utilized the Comprehensive Air Quality Model with Extensions (CAMx) air quality model with the Mesoscale Meteorological Model (MM5) and the Emission Modeling System (EMS-2003). Within the CAMx modeling system, MPCA used the Particulate Source Apportionment Tool (PSAT) and included evaluation of all the elevated point emissions[1] at each facility with best available retrofit technology (BART) units. The impacts from MPCA State Implementation Plan (SIP) BART controls were determined by subtracting the impact difference between the 2002/2005 base case and 2002/2005 BART control case for each facility. EPA used the impacts from four of the six facilities modeled by MPCA (Minnesota Power – Boswell Energy Center, Minnesota Power – Taconite Harbor, Northshore Mining – Silver Bay, United Taconite). The other two facilities modeled by MPCA were utility sources (Rochester Public Utilities – Silver Lake and Xcel Energy – Sherburne Generating Plant). The locations of these sources are presented below in Figure A-1 (obtained from the MPCA 2009 document).

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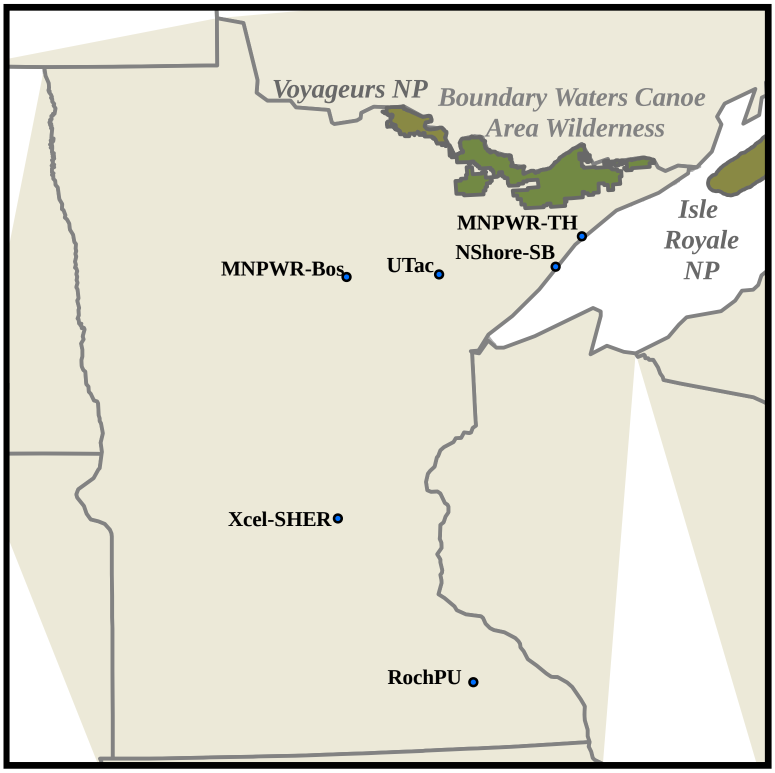
[1] Elevated point emissions include only sources with plume rise above 50m.

Figure A-1: Minnesota Facilities with BART-Determinations Assessed



In order to avoid the time and effort necessary for specific modeling of the units that EPA proposed to include in the FIP, EPA then used the average visibility impact from these four facilities to calculate two metrics for visibility improvement. The first metric is a ratio of number of days with greater than 0.5 deciview (dV) visibility divided separately by the change in SO_2 and NO_X emissions at each facility (i.e. one ratio for change in SO_2 emissions and one ratio for change in NO_X emissions). The second metric was calculated in the same fashion, but with 98th percentile visibility change divided by the change in SO_2 and NO_X emissions at each facility. These ratios were then multiplied by the estimated FIP emission reductions for the taconite facilities (including UTAC and Northshore Mining). It is important to note that there were no NO_X emission reductions modeled from any of the taconite facilities and the only source of SO_2 emission reductions from the taconite facilities was the UTAC facility.

Within the final FIP, EPA provided some additional statements that further clarified the agency's confidence regarding the use of the scalar approach for estimating visibility improvements.

III. Specific Issues Regarding EPA's Visibility Impact Estimates

Clean Air Act Section 169(A)(g)(2) – "In determining the best available retrofit technology the State (or the Administrator in determining emission limitations which reflect such technology) shall take into consideration the costs of compliance, the energy and nonair quality environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology."

Proposed FIP Page 49329 – Column 1 – "The discussion below uses MPCA's emissions data and modeled visibility impact data to derive visibility impact ratios as a function of changes in emissions of NOx and SO2 at MPCA-modeled facilities. These visibility-emission ratios were then applied to the BART-based emission changes for the source subject to this BART rule to derive possible visibility impacts."

Issues – EPA's shortcut methodology does not provide an accurate assessment of potential visibility impacts from taconite emission units subject to BART, and cannot be relied upon for several reasons stated below. The use of emission change vs. visibility impact ratios is not scientifically accurate even for a single source, much less several sources in other locations, and illustrates EPA's haste for the development of the FIP without proper modeling procedures. According to a plain language reading of the Clean Air Act section above and the best-practice recommendations within Appendix Y, the state and EPA were required to conduct a thorough evaluation of the impacts associated with the changes in emissions for each BART technology at the relevant units within each taconite facilities. EPA's methodology does not result in a thorough evaluation. If such an analysis were submitted to EPA by the state, it would be rejected as inadequate. The same should apply to EPA's analysis of the visibility improvement calculations.

MPCA used an appropriate model for estimating visibility impacts from five utility sources and one taconite source, all subject to BART, in northern Minnesota. EPA took that analyses and attempted to justify its outcomes based on its flawed methodology. Alone, the differences between the emission profiles for utility sources and taconite sources and their different locations relative to the Class I areas should preclude this type of evaluation. The difference in the emissions profile relationship between NO_X and SO_2 emissions is extremely important due to the interactive and competitive nature of the two pollutants for available ammonia (NH_3) to form ammonium nitrate or ammonium sulfate.

In addition, there are important seasonal differences in the tendency for sulfates or nitrates to be important for haze formation. Nitrates are only important in winter because significant particle formation occurs only in cold weather; oxides of nitrogen react primarily to form ozone in the summer months. On the other hand, oxidation of SO_2 to sulfate is most effective in summer with higher rates of photochemical and aqueous phase reactions. Due to the much different seasonal preferences for these two haze components, a one-size-fits-all scaling approach based upon annual averages that is insensitive to the season of the year is wholly inappropriate.

It is important to note that the only NO_X emission reductions used in the EPA scalar analyses were from utility sources. This occurred because the MPCA SIP did not include NO_X emission reductions from the United Taconite units. Therefore, the variation in emission profiles and stack parameters between utility boiler emission sources and taconite furnaces introduce another source of error with the EPA methodology.

Further, as shown in Figure A-1, the location of these sources with respect to the relevant Class I areas also causes significant problems with the EPA evaluation. The modeled visibility impacts from each source are a direct function of the wind direction. When two sources are not in the same direction with respect to the area, there is no possible way to accurately reflect the impact from the two different sources on receptor locations on any given day. For example, elevated impacts on the Voyageurs National Park from Northshore Mining would not happen on the same days as any of the other taconite sources in Minnesota.

Additionally, notwithstanding the inaccuracies of EPA's average scalar methodology, a review of the calculation of the visibility change to emission reduction ratios (i.e. MPCA-calculated visibility changes divided by SO_2 and NO_X SIP emission reductions) was conducted. This review uncovered calculation/typographical errors in the tables that were used to develop the average visibility change metrics. These simple calculation errors were subsequently corrected in the final FIP, but another inconsistency was not. The emission reductions used for NO_X within the scalar visibility calculations (Table V-C.xx) do not match the emission reduction tables in the proposed FIP (Table V – B.yy) for each facility. In one case (Northshore Mining Company), the visibility improvement reductions are greater than the baseline emissions. The attached table provides the baseline, proposed FIP, and final FIP information contained within the EPA rulemakings and docket for each taconite furnace and facility. Ultimately, even if the scalar approach used by EPA was valid, the rulemaking record is inaccurate and incomplete for the calculation of visibility impacts due to these inconsistencies.

Further, the calculation methodology for the two facilities with SO_2 and NO_X reductions (United Taconite and US Steel – Minntac) appears to utilize another invalid assumption. Also, the proposed FIP does not provide a clear explanation of the calculation of the scaled visibility impacts for these two facilities (Page 49332 – Column 1):

"To calculate the visibility impacts for the Minnesota source facilities covered by this FIP proposed rule, we multiplied the total estimated BART NOx and SO2 emission reductions for each subject facility by the appropriate visibility factor/emission change ratios in Table V-C.9 and combined the results to estimate the total visibility impacts that would result from the reduction of PM2.5 concentrations."

In Tables V-C.14 and V-C.16, the calculation of the visibility change with the two different pollutants is not explicitly provided within the FIP. Based on the use of the average visibility changes ("combined results") in the attached tables, one can generate "estimated visibility impacts" that are close to the values provided in the FIP tables. This pollutant averaging approach is not valid due to the previous comments regarding the interactive nature of the reaction mechanisms for ammonium nitrate and ammonium sulfate.

Proposed FIP Page 49331 – Column 1 – "The above visibility factor/emission change ratio data show significant variation from source-to-source and between impacted Class I areas. This variation is caused by differences in the relative location of the source (relative to the locations of the Class I areas), variations in background sources, variations in transport patterns on high haze factors, and other factors that we cannot assess without detailed modeling of the visibility impacts for the sources as a function of pollutant emission type."

Issue – EPA correctly establishes the significant variation in the ratio data and clearly distinguishes some (but not all) of the problems with the approach used to determine visibility impacts. Other problems include the differences in modeled utility source stack parameters vs. taconite stack parameters, the different inter-pollutant ratios at each facility, and the differences in visibility impacts due to on-going changes in emissions from 2002/2005 to current/future emission levels. Furthermore, EPA identifies the solution to solve this problem within their statement regarding "detailed modeling of the visibility impacts". This detailed modeling exercise was completed for BART-eligible Cliffs Natural Resources and Arcelor Mittal facilities in northeast Minnesota and Michigan to provide a clear record of the visibility improvements associated with the final FIP. This modeling demonstrates the lack of visibility improvement from nearly 15,000 tons per year of NO_X emission reductions and provides sufficient evidence to support the Minnesota and Michigan State Implementation Plans which called for good combustion practices as BART for NO_X at these facilities.

Proposed FIP Page 49333, Column 2 – "Each BART determination is a function of consideration of visibility improvement and other factors for the individual unit, but in general EPA's assessment of visibility impacts finds that technically feasible controls that are available at a reasonable cost for taconite plants can be expected to provide a visibility benefit that makes those controls warranted."

Issue – EPA's statement regarding visibility benefit from the FIP NO_X emission reductions are vastly overestimated based on updated CAM_X modeling for the Cliffs Natural Resources and Arcelor Mittal taconite furnaces. The modeling results evaluating the 98th percentile visibility improvements obtained from these emission reductions are generally less than 10% of the EPA estimates. Therefore, these NO_X controls are not warranted for visibility improvement in northeast Minnesota and Michigan.

Final FIP Page 8720, Column 2 – "EPA's analysis shows that based on all of the BART factors, including visibility, the selected controls are warranted. If highly reasonable and cost-effective controls had been available but visibility benefits were slight, EPA would have rejected those controls."

Issue – EPA describes exactly the situation with respect to "slight visibility benefits". Therefore, given the new information regarding the very slight modeled impact of NO_X emission reductions, EPA should reject those reductions as necessary under the BART program. Also, in the final FIP, EPA criticizes both MPCA and MDEQ for ignoring relevant information on Low NO_X Burner (LNB) technology. Now, given the length of time necessary and extensive effort required to generate this new visibility improvement data, EPA should reconsider its position on LNB as producing visibility benefits. This would allow EPA to support the original findings for these facilities within both the MPCA and MDEQ SIP with respect to NO_X emission limits.

Final FIP Page 8720, Column 3 – "EPA's proposed rule acknowledged the uncertainty associated with the visibility impact ratio approach, but noted that despite the uncertainties, the Agency was confident that the information was adequate to assess potential visibility improvements due to emission reductions at the specific facilities."

"Given the geographic proximity of the taconite facilities to those that were modeled, EPA believes that the ratio approach provide adequate assurance of the visibility improvements that can be expected from the proposed emission reductions."

"In the proposed rule's summary of the impacts at Boundary Waters, Voyageurs, and Isle Royale, these values ranged from 1.3 to 7.1 dVs of improvement with between 17 and 93 fewer days above the 0.5 dV threshold. Therefore, even if the ratio approach was over-estimating visibility improvements by a factor of two or three, the expected benefits would still be significant."

Final FIP Page 8721, Column 3 – "EPA stands by the results of its ratio approach and believes that it produced reasonable results for the sources examined."

Issue – EPA again chose to ignore the specific technical issues discussed above regarding the use of the ratio approach and has incorrectly assumed that this approach will provide an accurate assessment of the visibility benefits from the Cliffs and Arcelor taconite facilities. Based on the refined CAM_X modeling results using a conservative estimate of EPA's final FIP emission reduction scenario, it is obvious that the ratio approach does not provide any assurance of the visibility improvements. Further, the estimates for visibility improvement are over-estimated by between a factor of ten and sixty. Therefore, the impacts are not "significant" as referenced in EPA's response to comment within the final FIP rulemaking. The lack of technical validity contained within the EPA scalar approach is alarming. Even more alarming is the agency's refusal to conduct the type of detailed analyses necessary to allow for a technically valid answer on a rulemaking that will cost the taconite industry millions of dollars.

IV. Summary

The CAM_X modeling approach undertaken by Cliffs and Arcelor provides the best approximation of the visibility improvements from the emission reductions within the final FIP. This method replaces the use of the average ratio approach used by EPA with refined, photochemical modeling for the Cliffs and Arcelor facilities. The results of the analysis confirm the findings of the MPCA in its 2009 SIP that NO_X emission reductions do not have sufficient impact to warrant further consideration. At this point, we affirm that EPA's simple assessment is not credible, and any visibility improvement conclusions for NO_X are not technically sound. The visibility improvement results estimated by EPA using the ratio approach are between ten and sixty times greater than the results generated using the CAM_X modeling system. In essence, the modeling conducted here provides EPA another opportunity to support the findings of the MPCA and MDEQ SIPs with respect to NO_X emissions impacts at the Cliffs and Arcelor facilities.

Cliffs Natural Resources and Arcelor Mittal Taconite FIP Emission Summary

				Emissions			Emission Reductions			Emissions	
				Proposed FIP			Baseline - Prop FIP	Baseline - Prop FIP		Final FIP	
Facility	Emission Unit		Pollutant	Baseline	FIP		Emission Tables	Visibility Calcs			
	ModID	Description		tons/yr	tons/yr	Note(s)	tons/yr	tons/yr	Note(s)	lb/hr	Note(s)
Hibbing Taconite Company	{3}	Line 1	NOx	2,497	749	[1]	1,748				[4]
			SO2	202	202	[2]	0			82.6	[5]
	{4}	Line 2	NOx	2,144	643	[1]	1,500				[4]
			SO2	180	180	[2]	0			82.6	[5]
	{5}	Line 3	NOx	2,247	674	[1]	1,573				[4]
			SO2	188	188	[2]	0			82.6	[5]
	HTC	BART Units Combined	NOx	6,888	2,066		**4,821**	**5,259**	[3]		
			SO2	570	570		0	0	[3]	247.8	
Northshore Mining Company		Process Boiler 1/2	NOx	41	21	[6]	21				[10]
			SO2								
	{24}	Furnace 11	NOx	386	116	[7]	270				[11]
			SO2	38	38	[8]	0			19.5	[12]
	{25}	Furnace 12	NOx	378	113	[7]	264				[11]
			SO2	35	35	[8]	0			19.5	[12]
	NSM	BART Units Combined	NOx	805	250		**555**	**926**	[9]		
			SO2	73	73		0	0	[9]	39	
Tilden Mining Company	{1}	Boiler #1/2	NOx	79	79	[13]	0				
			SO2	0	0	[14]	0				[19]
	{3}	Ore Dryer # 1	NOx	15	15	[15]	0				
			SO2	34	34	[15]	0				[20]
	{5}	Furnace #1	NOx	4,613	1,384	[16]	3,229				[21]
			SO2	1,153	115	[17]	1,038			55	[22][23]
	TMC	BART Units Combined	NOx	4,707	1,478		3,229	3,229	[18]		
			SO2	1,187	150		1,038	1,038	[18]		
United Taconite	{26}	Line 1	NOx	**1,643**	493	[24]	1,150				[27]
			SO2	1,293	129	[25]	1,164			155	[28]
	{24}	Line 2	NOx	**3,687**	1,106	[24]	2,581				[27]
			SO2	2,750	275	[25]	2,475			374	[28]
	UTAC	BART Units Combined	NOx	5,330	1,599		**3,731**	**3,208**	[26]		
			SO2	4,043	404		3,639	3,639	[26]	529	[28]
Arcelor Mittal	ARC {12}	Line 1	NOx	3,639	1,092	[29]	**2,547**	**2,859**	[31]		[32]
			SO2	179	179	[30]	0	0	[31]	38.2	[33]

TOTAL BART UNIT	NOx	21,369	6,485		14,884	15,481
	SO2	6,053	1,376		4,677	4,677

🟨	Facility BART Unit Summary or Overall Summary	EPA Furnace
🟩	FIP Baseline does not match reference	NOx Control %
🟧	FIP Table B emission tables do not match Table C visibility calculation tables	70%

Notes:

[1] HTC Line 1-3 - USEPA FIP NOx Baseline Emissions Proposed FIP Table V - B.24 ; Proposed FIP NOx Emissions = 70% Control from Baseline
Typographical Error in Table V - B.24 for Line 1 Baseline Emissions (2,143.5 TPY Proposed FIP; should have been 2,497 TPY)
[2] HTC Line 1-3 - USEPA FIP SO2 Baseline Emissions from Proposed FIP Table V - B.27
[3] HTC - USEPA Proposed BART FIP Table V - C.11
[4] HTC Furnace Lines - USEPA Final BART limit of 1.5 lb NOx/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only).
[5] HTC Furnace Lines - USEPA final BART combined limit of 247.8 lb SO2/hr [82.6 lb/hr each for Lines 1 to 3] (30-day rolling avg); can be adjusted based on CEMs data.
[6] NSM Process Boilers 1&2 - NOx Emissions from Proposed FIP Table V - B.12 (p49318); LNB 50% Control from Baseline of 41.2 tons/year
[7] NSM Furnace 11/12 - NOx Emissions (Baseline and Proposed FIP Control) from Proposed FIP - Table V - B.8; FIP Emisssions = 70% Control from Baseline
[8] NSM Furnace 11/12 - No Additional SO2 Control Applied by Proposed FIP; Baseline FIP Emission Rate from Table V - B.10
[9] NSM - USEPA Proposed BART FIP Table V - C.12
[10] NSM Process Boilers 1&2 - USEPA Final BART limit of 0.085 lb NOx/MMBTU (30-day rolling average) [No additional control].
[11] NSM Furnace 11/12 - USEPA Final BART limit of 1.5 lb NOx/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only).
[12] NSM Furnace 11/12 - USEPA final BART combined limit of 39.0 lb SO2/hr (30-day rolling average); must be adjusted based on CEMs data.
[13] Tilden Process Boilers 1 & 2 - NOx Baseline Emissions Proposed FIP Table V - B.38
[14] Tilden Process Boilers 1 & 2 - SO2 Baseline Emissions Proposed FIP Table V - B.37 (0.25 TPY)
[15] Tilden Dryer #1 Emissions from Proposed FIP Table V - B.39 (SO2) and Table V - B.40 (NOx) - 34.07 TPY SO2, 15.1 TPY NOx
[16] Tilden Furnace 1 - NO2 Baseline and Proposed FIP Control Emissions - Proposed FIP Table V - B.34 (FIP Emissions = 70% Control from Baseline)
[17] Tilden Furnace 1 - Proposed FIP SO2 Emissions - Table V-B.36; Spray Dry Absorption 90%; Proposed FIP Text says 95% Control or 5 ppm;
Baseline Emissions Back-calculated from 90% control
[18] Tilden Furnace 1 - USEPA did not calculate visibility improvement for Tilden (Used emission difference Baseline - Proposed FIP)
[19] Tilden - USEPA Final BART limit of 1.2%S in fuel combusted by Process Boiler #1 and #2
[20] Tilden - USEPA Final BART limit of 1.5%S in fuel combusted by Ore Dryer #1
[21] Tilden Furnace 1- USEPA Final BART limit of 1.5 lb NOx/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only);
NOx emissions referenced in final FIP text as 65% control from baseline (page 8721)
[22] Tilden Furnace 1 - USEPA Final BART restriction - Only combust natural gas in Grate Kiln Line 1 with limit computed in lb SO2/hr based on CEMs;
SO2 emissions referenced in final FIP text at 80% control from baseline (page 8721)
[23] Tilden Furnace 1 - USEPA Final BART Modeling File (Part of Final Rulemaking Docket) Conducted by NPS - 55 lb/hr SO2
[24] UTAC Line 1-2 - USEPA NOx Baseline Emissions Proposed FIP Table V - B.14 ; Proposed FIP NOx Emissions = 70% Control from Baseline
[25] UTAC Line 1-2 - USEPA proposed FIP Baseline SO2 Emissions Table V - B.17; 90% Control in Table, but 95% Control within text - Proposed FIP (page 49319)
[26] UTAC - USEPA Proposed BART FIP Table V - C.13
[27] UTAC Line 1-2 - USEPA Final BART NOx Limit of 1.5 lb/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only)
[28] UTAC Line 1-2 - USEPA Final BART SO2 Limit of 529 lb/hr Combined (155 lb/hr - Line 1 & 374 lb/hr - Line 2).
[29] Arcelor - USEPA proposed FIP Baseline NOx Emissions Table V - B.19; Proposed FIP NOx Emissions = 70% Control from Baseline
[30] Arcelor - USEPA proposed FIP Baseline SO2 Emissions Table V - B.21
[31] Arcelor - USEPA Proposed BART FIP Table V - C.10
[32] Arcelor - USEPA Final BART SO2 Limit of 38.16 lb/hr for Arcelor.
[33] Arcelor - USEPA Final BART NOx Limit of 1.5 lb/MMBTU (30-day rolling average); 1.2 lb NOx/MMBTU (30-day consecutive gas firing only)

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APPENDIX B: Barr and MPCA CAM$_X$ Modeling Comparison of Results

March 6, 2013

Minnesota Power – Taconite Harbor (BART01)

MPCA
Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	94	90	-4	11	9	-2	30	27	-3
98th Percentile Δ dv	**2002**	9.2	8.3	-0.9	0.8	0.7	-0.1	2.2	1.9	-0.3

Barr
Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	95	90	-5	11	9	-2	30	27	-3
98th Percentile Δ dv	**2002**	9.14	8.25	-0.89	0.82	0.68	-0.14	2.22	1.88	-0.34

Minnesota Power – Boswell (BART04)

MPCA
Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**DifferEnce**	**Base**	**BART**	**Difference**	**Base**	**BART**	**DifferEnce**
Days > 0.5 dv	**2002**	111	60	-51	86	58	-28	48	27	-21
98th Percentile Δ dv	**2002**	4.3	2.4	-1.9	4.4	2.7	-1.8	2.0	1.0	-1.0

Barr
Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	**Met Year**	**Base**	**BART**	**DifferEnce**	**Base**	**BART**	**Difference**	**Base**	**BART**	**Difference**
Days > 0.5 dv	**2002**	110	61	-49	86	58	-28	47	27	-20
98th Percentile Δ dv	**2002**	4.27	2.37	-1.90	4.43	2.65	-1.78	1.96	0.98	-0.98

Northshore Mining – Silver Bay (BART05)

MPCA
Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

PM$_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Difference	Base	BART	Difference	Base	BART	Difference
Days > 0.5 dv	2002	77	72	-5	9	8	-1	20	15	-5
98th Percentile Δ dv	2002	3.96	3.79	-0.17	0.6	0.5	-0.1	0.9	0.7	-0.2

Barr
Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

PM$_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Difference	Base	BART	Difference	Base	BART	Difference
Days > 0.5 dv	2002	78	72	-6	9	8	-1	20	15	-5
98th Percentile Δ dv	2002	3.96	3.78	-0.18	0.63	0.50	-0.13	0.90	0.73	-0.17

United Taconite (BART26)

MPCA
Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

PM$_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Difference	Base	BART	Difference	Base	BART	Difference
Days > 0.5 dv	2002	59	44	-15	32	20	-12	8	1	-7
98th Percentile Δ dv	2002	3.0	1.7	-1.3	1.8	0.8	-0.9	0.6	0.3	-0.3

Barr
Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

PM$_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Difference	Base	BART	Difference	Base	BART	Difference
Days > 0.5 dv	2002	63	46	-17	34	20	-14	8	1	-7
98th Percentile Δ dv	2002	3.02	1.69	-1.33	1.78	0.85	-0.93	0.59	0.28	-0.31

Xcel Sherburne (BART13)

MPCA

Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Difference	Base	BART	Difference	Base	BART	Difference
Days > 0.5 dv	2002	74	58	-16	53	39	-14	42	30	-12
98th Percentile Δ dv	2002	2.5	1.9	-0.6	2.2	1.7	-0.5	1.4	1.0	-0.4

Barr

Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Difference	Base	BART	Difference	Base	BART	Difference
Days > 0.5 dv	2002	74	59	-15	53	39	-14	42	29	-13
98th Percentile Δ dv	2002	2.48	1.90	-0.58	2.18	1.65	-0.53	1.44	1.06	-0.38

Rochester Public Utilities (BART07)

MPCA

Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Difference	Base	BART	Difference	Base	BART	Difference
Days > 0.5 dv	2002	0	0	0	0	0	0	0	0	0
98th Percentile Δ dv	2002	0.1	0.1	0.0	0.1	0.0	0.0	0.1	0.0	0.0

Barr

Number of Days with Results > 0.5 dv and 98th Percentile Deciview Value

$PM_{2.5}$		Class I Area								
		Boundary Waters			Voyageurs			Isle Royale		
Parameter	Met Year	Base	BART	Difference	Base	BART	Difference	Base	BART	Difference
Days > 0.5 dv	2002	0	0	0	0	0	0	0	0	0
98th Percentile Δ dv	2002	0.10	0.06	0.04	0.08	0.04	0.04	0.09	0.04	0.05

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APPENDIX C: CAM$_X$ PSAT Source List

March 6, 2013

2009 MPCA Tracked, Elevated Point Sources

RANKTRAC BARTSRC_ID	RECEPTOR BARTSRC_ID	Facility ID	Facility Name [1]
1	2	2703100001	Minnesota Power - Taconite Harbor
2	3	2703700003	XCEL - Black Dog
3	4	2705300015	XCEL - Riverside
4	5	2706100004	Minnesota Power - Boswell
5	6	2707500003	Northshore Mining Co - Silver Bay
6	7	2709900001	Austin Utilities - NE Power Station
7	8	2710900011	Rochester Public Utilities
8	9	2711100002	Otter Tail Power - Hoot Lake
9	10	2712300012	XCEL - High Bridge
10	11	2713700013	Minnesota Power - Laskin
11	12	2713700027	Hibbing Public Utilities
12	13	2713700028	Virginia Dept of Public Utilities
13	14	2714100004	XCEL - Sherburne Generating Plant
14	15	2716300005	XCEL - Allen S. King
15	16	2701700002	Sappi - Cloquet
16	17	2703700011	Flint Hill Resources - Pine Bend
17	18	2706100001	Blandin Paper / Rapids Energy
18	19	2707100002	Boise Cascade - International Falls
19	20	2713700005	US Steel - Minntac
20	21	2713700015	Minnesota Power - ML Hibbard
21	22	2713700022	Duluth Steam Cooperative
22	23	2713700031	Georgia Pacific - Duluth
23	24	2713700061	Hibbing Taconite
24	25	2713700062	Arcelor Mittal
25	26	2713700063	US Steel - Keetac
26	27	2713700113	United Taconite - Fairlane Plant [2]
27	28	2700900011	International Paper - Sartell
28	29	2716300003	Marathon Ashland Petroleum
29	30	2713700083	Potlatch - Cook
30	31	2706100010	Potlatch - Grand Rapids

🟨 Included in MPCA BART SIP Modeling Report

[1] MPCA tracked all point sources on a facility-basis

[2] MPCA Emissions did not Include UTAC Line 1

2012/2013 Barr Tracked, Elevated Point Sources

Output ID	BARTSRC_ID	Facility ID	Facility / Unit Name [3]
MNPWTH	2	2703100001	Minnesota Power - Taconite Harbor
XCELBD	3	2703700003	XCEL - Black Dog
XCELRV	4	2705300015	XCEL - Riverside
MNPWBO	5	2706100004	Minnesota Power - Boswell
NSMSBU	6	2707500003	Northshore Mining Co - Silver Bay (All Other)
AUSTIN	7	2709900001	Austin Utilities - NE Power Station
ROCHPU	8	2710900011	Rochester Public Utilities
OTTRHL	9	2711100002	Otter Tail Power - Hoot Lake
XCELHB	10	2712300012	XCEL - High Bridge
MNPWLS	11	2713700013	Minnesota Power - Laskin
HIBBPU	12	2713700027	Hibbing Public Utilities
VIRGPU	13	2713700028	Virginia Dept of Public Utilities
XCELSB	14	2714100004	XCEL - Sherburne Generating Plant
XCELAK	15	2716300005	XCEL - Allen S. King
SAPPIC	16	2701700002	Sappi - Cloquet
FHRPNB	17	2703700011	Flint Hill Resources - Pine Bend
BLNPAP	18	2706100001	Blandin Paper / Rapids Energy
BOISEC	19	2707100002	Boise Cascade - International Falls
MINNTC	20	2713700005	US Steel - Minntac
MNPWHB	21	2713700015	Minnesota Power - ML Hibbard
DULSTM	22	2713700022	Duluth Steam Cooperative
GEOPAC	23	2713700031	Georgia Pacific - Duluth
HIBTAC	24	2713700061	Hibbing Taconite (All Other)
ARCELR	25	2713700062	Arcelor Mittal (All Other)
KEETAC	26	2713700063	US Steel - Keetac
UTACFP	27	2713700113	United Taconite - Fairlane Plant (All Other)
INTPAP	28	2700900011	International Paper - Sartell
MARTHN	29	2716300003	Marathon Ashland Petroleum
POTLTC	30	2713700083	Potlatch - Cook
POTLTG	31	2706100010	Potlatch - Grand Rapids
TILDEN	32	26103B4885	Tilden Mining Company (All Other)
NSMPB1	33	2707500003	Northshore Mining - Power Boiler 1
NSMPB2	34	2707500003	Northshore Mining - Power Boiler 2
NSMF11	35	2707500003	Northshore Mining - Furnace 11
NSMF12	36	2707500003	Northshore Mining - Furnace 12
UTACL1	37	2713700113	United Taconite - Line 1
UTACL2	38	2713700113	United Taconite - Line 2
ARCLN1	39	2713700062	Arcelor Mittal - Line 1
HBTCF1	40	2713700061	Hibbing Taconite - Line 1
HBTCF2	41	2713700061	Hibbing Taconite - Line 2
HBTCF3	42	2713700061	Hibbing Taconite - Line 3
TILDL1	43	26103B4885	Tilden Mining - Line 1

🟩	Included in Barr Output Evaluation
[3]	Barr tracked furnace stacks and other noted stacks on a unit-basis while all other stacks were included in the "All Other" stacks

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APPENDIX D: Summary of CAM$_X$ Elevated Point Source Emissions

March 6, 2013

Summary of CAMx Elevated Point Source Emissions

				Emissions		Emissions		Emission Reductions
				Proposed FIP		Final FIP		Baseline - Final FIP
	Emission Unit		Pollutant	Baseline		FIP		
Facility	ModID	Description		tons/yr	Note(s)	tons/yr	Note(s)	tons/yr
Hibbing Taconite Company	{3}	Line 1	NOx	2,497	[1]	749	[3]	1,748
			SO2	202	[2]	202	[4]	0
	{4}	Line 2	NOx	2,144	[1]	643	[3]	1,500
			SO2	180	[2]	180	[4]	0
	{5}	Line 3	NOx	2,247	[1]	674	[3]	1,573
			SO2	188	[2]	188	[4]	0
	HTC	BART Furnaces Combined	NOx	6,888		2,066		4,821
			SO2	570		570		0
Northshore Mining Company		Process Boiler 1/2	NOx	41	[5]	41	[8]	0
			SO2					
	{24}	Furnace 11	NOx	386	[6]	116	[9]	270
			SO2	38	[7]	38	[10]	0
	{25}	Furnace 12	NOx	378	[6]	113	[9]	264
			SO2	35	[7]	35	[10]	0
	NSM	BART Furnaces Combined	NOx	764		229		535
			SO2	73		73		0
Tilden Mining Company	{1}	Boiler #1/2	NOx	79	[11]	79	[16]	0
			SO2	0	[12]	0	[17]	0
	{3}	Ore Dryer # 1	NOx	15	[13]	15	[18]	0
			SO2	34	[13]	34	[19]	0
	{5}	Furnace #1	NOx	4,613	[14]	1,384	[20]	3,229
			SO2	1,153	[15]	231	[21]	922
	TMC	BART Furnace	NOx	4,613		1,384		3,229
			SO2	1,153		231		922
United Taconite	{26}	Line 1	NOx	**1,643**	[22][23]	493	[26]	1,150
			SO2	1,293	[25]	577	[27]	716
	{24}	Line 2	NOx	**3,687**	[22][24]	1,106	[26]	2,581
			SO2	2,750	[25]	1,392	[27]	1,357
	UTAC	BART Furnaces Combined	NOx	5,330		1,599		3,731
			SO2	4,043		1,969		2,074
Arcelor Mittal	ARC {12}	Line 1	NOx	3,639	[28]	1,092	[30]	2,547
			SO2	179	[29]	179	[31]	0

TOTAL BART Furnaces	NOx	21,233		6,370		14,863
	SO2	6,018		3,022		2,996

🟨 Facility Furnace Unit Summary or Overall Summary
🟩 FIP Baseline does not match reference

Notes:

[1] HTC Line 1-3 - USEPA FIP NOx Baseline Emissions Proposed FIP Table V - B.24
[2] HTC Line 1-3 - USEPA FIP SO2 Baseline Emissions from Proposed FIP Table V - B.27
[3] HTC Line 1-3 - USEPA Proposed FIP NOx = 70% control from Baseline - Table V - B.24; Final FIP (1.2 or 1.5 lb/MMBTU) assumed equivalent
[4] HTC Line 1-3 - USEPA Final FIP - no additional SO2 control (Final FIP = Baseline Emissions)
[5] NSM Process Boilers 1&2 - NOx Emissions from Proposed FIP Table V - B.12 (p49318)
[6] NSM Furnace 11/12 NOx Emissions from Proposed FIP - Table V - B.8
[7] NSM Furnace 11/12 SO2 Baseline FIP Emission Rate from Proposed FIP Table V - B.10
[8] NSM Process Boilers #1 and #2 - USEPA Final BART limit of 0.085 lb NOx/MMBTU (30-day rolling average) - No additional control.
[9] NSM Furnace 11/12 - USEPA Proposed FIP NOx = 70% control from Baseline _ Table V - B.8; Final FIP (1.2 or 1.5 lb/MMBTU) assumed equivalent
[10] NSM Furnace 11/12 - no Additional SO2 Control Applied by Proposed or Final FIP (Final FIP = Baseline Emissions)
[11] Tilden Process Boilers 1 & 2 NOx Baseline Emissions Proposed FIP Table V - B.38
[12] Tilden Process Boilers 1 & 2 SO2 Baseline Emissions Proposed FIP Table V - B.37 (0.25 TPY)
[13] Tilden Dryer #1 Emissions from Proposed FIP Table V - B.39 (SO2) and Table V - B.40 (NOx) - 34.07 TPY SO2, 15.1 TPY NOx
[14] Tilden Furnace 1 NO2 Baseline - Proposed FIP Table V - B.34
[15] Tilden Furnace 1 SO2 Baseline - Proposed FIP Projected SO2 Emission Reductions - Table V-B.36; Baseline Emissions Back-calculated from 90% control
[16] Tilden Process Boilers 1 & 2 - No additional NOx control (Final FIP = Baseline Emissions)
[17] Tilden Process Boilers 1 & 2 - USEPA Final BART limit of 1.2%S in fuel - No additional SO2 control (Final FIP = Baseline Emissions)
[18] Tilden Ore Dryer #1 - No additional NOx control (Final FIP = Baseline Emissions)
[19] Tilden Ore Dryer #1 - USEPA Final BART limit of 1.5%S in fuel - No additional SO2 control (Final FIP = Baseline Emissions)
[20] Tilden Furnace 1 - USEPA Proposed FIP NOx = 70% control from Baseline _ Table V - B.34; Final FIP (1.2 or 1.5 lb/MMBTU)
NOx emissions referenced in final FIP text at 65% control from baseline (page 8721); but that is not consistent with the remaining facilities
Modeled emissions assumed 70% control to provide maximum emission reductions
[21] Tilden - USEPA Final BART restriction - Only combust natural gas in Grate Kiln Line 1 with limit computed in lb SO2/hr based on CEMs;
SO2 emissions referenced in final FIP text at 80% control from baseline (page 8721)
[22] UTAC - USEPA FIP NOx Baseline Emissions Proposed FIP Table V - B.14
[23] UTAC - Line 1 NOx Permit limit specified in permit 13700113-005 - 1,655 TPY, issued 8/19/2010, page A-49 (reference from USEPA 114 Request Question 6)
[24] UTAC - Line 2 NOx Permit limit specified in permit 13700113-005 - 3,692 TPY, issued 8/19/2010, page A-56 (reference from USEPA 114 Request Question 6)
[25] UTAC Line 1&2 - USEPA proposed FIP Baseline SO2 Emissions Table V - B.17; 90% Control in Table, 95% Control within text _ Proposed FIP (page 49319)
Modeled baseline emissions back-calculated from 90% Control; SO2 Reductions match Table V - C.13 in Proposed FIP
[26] UTAC Line 1&2 - USEAP Proposed FIP NOx = 70% Control from Baseline Table V - B.14; Final FIP (1.2 or 1.5 lb/MMBTU)
Modeled emissions assumed 70% control to provide maximum emission reductions
[27] UTAC Line 1&2 - USEPA Final BART SO2 Limit of 529 lb/hr Combined (155 lb/hr - Line 1 & 374 lb/hr - Line 2) - 30-day rolling average.
Modeled Final FIP emissions used the limits and 85% operating factor to calculate the annual emissions (designed to maximize reductions)
[28] Arcelor Line 1 - USEPA proposed FIP Baseline NOx Emissions Table V - B.19
[29] Arcelor Line 1 - USEPA proposed FIP Baseline SO2 Emissions Table V - B.21
[30] Arcelor Line 1 - Proposed FIP NOx = 70% Control from Baseline Table V - B.19; Final FIP (1.2 or 1.5 lb/MMBTU) assumed equivalent
[31] Arcelor Line 1 - USEPA Final FIP - no additional SO2 control (Final FIP = Baseline Emissions)

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APPENDIX E: Electronic Mail Requests - Proposed and Final FIP Emission Clarifications

March 6, 2013

From: Jeffry D. Bennett
Sent: Thursday, January 31, 2013 7:42 PM
To: 'Rosenthal.steven@Epa.gov'
Cc: 'Long, Michael E'
Subject: Clarification Regarding Emissions within the Final Taconite BART FIP
Attachments: EPA_FIP_Emission_Summary_01292013.xls

Steve,

Pursuant to our conversation last week regarding the baseline and controlled emission inventories within the proposed and final BART FIP for taconite furnaces, this e-mail is designed to request clarification regarding certain information contained in the rule. To that end, attached you will find a spreadsheet that summarizes and documents (to the maximum extent possible) the emission inventory data within the FIP rulemakings.

Specifically at this time, we are requesting:

(1) verification of the UTAC baseline NOx information for Line 1 and Line 2 ('Summary' Tab, Cells E30 and E32),

(2) clarification of the differences between the information contained in Columns H and I of the spreadsheet, Column H contains the difference between the FIP baseline and proposed FIP control emissions and was calculated from information within Table V-B.xx* - NOx or SO2 facility specific emission data. The Column I information contains the emission reductions obtained from Table V-C.yy visibility improvement estimate tables. For each facility, these two columns should match, but the NOx information does not. Ultimately, the bases for Table V-C.yy data is the component that is missing.

*Note: for Hibbing Taconite Line 1, a typographical error was discovered in Table V-B.24 and corrected in the spreadsheet.

(3) EPA's estimates of final FIP emissions on a tons/year basis with the corresponding emission reductions (i.e. FIP baseline – final FIP control) expected by EPA. This information would replace the "?" in Columns L and M of the spreadsheet. Along with the estimates, documentation of their bases would be extremely beneficial. For example, NOx could include either a % reduction from baseline or MMBTU/hour, Hours/year, and the appropriate lb NOx/MMBTU limit.

If you have any questions regarding these requests, feel free to contact Mike Long or myself. Thank you for your time.

Jeffry D. Bennett, PE
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JBennett@barr.com
www.barr.com

From: Jeffry D. Bennett
Sent: Thursday, February 14, 2013 12:02 PM
To: 'Robinson.randall@Epa.gov'
Subject: FW: Clarification Regarding Emissions within the Final Taconite BART FIP
Attachments: EPA_FIP_Emission_Summary_01292013.xls

Randy,

I talked with Steve Rosenthal yesterday about the taconite BART FIP emissions (see e-mail below). He told me that you “wrote the section on visibility improvement” and suggested I contact you about item 2 and a portion of the information requested in item 3. Barr Engineering is contracted with Cliffs Natural Resources and Arcelor Mittal to provide their taconite facilities with technical support regarding the FIP. At this point, we are trying to summarize and document the bases for the SO2 and NOx emissions that were used in the EPA baseline, the proposed FIP, and the final FIP for all their facilities.

The attached spreadsheet that I sent Steve previously includes the summary. Item 2 is related to differences between the NOx emission reductions used in the ratio visibility improvement calculations in the proposed FIP (Table V – C.yy) and the emission reductions in Table V – B.xx for each facility. Steve thought you would have the information about the basis for the Table V – C.yy reductions.

Item 3 is requesting information about the final FIP emission reductions. Specifically, you would probably have information regarding the emissions for Tilden Mining and United Taconite (UTAC) from the CALPUFF modeling completed by Trent Wickman referenced in the final FIP rulemaking docket. Please give me a call to discuss this at your earliest convenience. We are attempting to finalize the summary by COB tomorrow. Thanks for any help you can provide.

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APPENDIX F: CAMx Modeling Results by Facility

March 6, 2013

Arcelor Mittal CAMx Emissions and Modeling Results

Arcelor Emissions

Unit	EPA FIP Baseline NOx Emission (TPY) [1]	Final FIP NOx Emission (TPY) [1]	NOx Emission Difference (TPY)	EPA FIP Baseline SO2 Emission (TPY) [2]	Final FIP SO2 Emission (TPY)[3]	SO2 Emission Difference (TPY)
Line 1	3,639	1,092	2,547	179	179	0
TOTAL	**3,639**	**1,092**	**2,547**	**179**	**179**	**0**

[1] FIP Baseline and Control NOx Emissions from EPA Proposed FIP Table V-B.19 – Projected Annual NOx Emission Reductions [TPY].

[2] FIP Baseline SO2 Emissions are from EPA Proposed FIP Table V-B.21 – Annual SO2 Emissions [TPY]

[3] No SO2 emission reductions in Final FIP (i.e. EPA Baseline = Final FIP control)

Arcelor CAMx Results (By Unit) [4]

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Proposed FIP Days > 0.5 dV	Proposed FIP 98% dV	Difference Days >0.5 dV [5]	Difference 98% dV [5]
Boundary Waters						
2002						
Line #1	30	0.789	18	0.713	12	0.076
Facility Total	43	0.99	35	0.96	8	0.03
2005						
Line #1	7	0.491	3	0.326	4	0.165
Facility Total	19	0.74	8	0.55	11	0.19
Voyageurs						
2002						
Line #1	1	0.287	0	0.202	1	0.085
Facility Total	1	0.34	0	0.22	1	0.12
2005						
Line #1	0	0.182	0	0.122	0	0.060
Facility Total	0	0.22	0	0.16	0	0.06
Isle Royale						
2002						
Line #1	0	0.075	0	0.053	0	0.022
Facility Total	0	0.09	0	0.06	0	0.03
2005						
Line #1	0	0.049	0	0.033	0	0.016
Facility Total	0	0.06	0	0.04	0	0.02

[4] Visibility benchmarks:

0.5 dV impact is the BART eligibility threshold (i.e. if a facility has less than 0.5 dV impact in the baseline, no BART is required),

1.0 dV difference is the presumed human perceptible level for visibility improvement, and

0.1 dV difference was defined by other agencies as the degree of visibility improvement that is too low to justify additional emission controls. Also, EPA's Regional Haze Rule mentions that "no degradation" to visibility would be "defined as less than a 0.1 deciview increase."

[5] These two columns provide the difference in predicted days >0.5 dV and 98th percentile visibility improvement from the baseline to the FIP control emissions. The annual average number of days with > 0.5 dV improvement at all the Class I areas is considerably less than EPA's estimate (11 to 53). Also, the averages of the 98th percentile differences are **10 to 37 times less** than the predicted improvement by EPA. Note: the table below formed the basis for EPA's inclusion of control necessary at Arcelor Mittal.

Arcelor Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

(EPA Table C Emission Difference = 2,859 TPY NOx)[6]

(EPA Table B Emission Difference = 2,547 TPY NOx)[7]

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV[8]	CAMx Modeled Difference 98% dV
Boundary Waters	24	1.7		10	0.11
Voyageurs	11	0.9		1	0.09
Isle Royale	18	1.1		0	0.03

[6] Emission Difference Obtained from EPA Proposed FIP Table V-C.10 – Estimated Emission Reductions and Resulting Changes in Visibility Factors for Arcelor Mittal.

[7] Emission Difference Obtained from EPA Proposed FIP Table V-B.19.

[8] The number of days with visibility >0.5 deciviews (dV) can be a misleading indicator as illustrated by the Arcelor Mittal and Northshore Mining results (below). The 98th percentile visibility improvement at Boundary Waters during the 2002 modeled year was 0.03 dV. However, the modeling predicts this insignificant change will result in eight more days of "good visibility", defined as days with visibility at or below the 0.5 deciview threshold. Further, the Northshore Mining results at Isle Royale indicate a miniscule 0.01 deciviews, or one hundred times less than a perceptible improvement to visibility. Nonetheless, the modeling predicts this insignificant change will result in two more days of "good visibility". In both circumstances, this does not mean that the visibility change was discernible. The model gives credit for an improved day when the predicted impairment falls from 0.51 to 0.50 deciviews, but that improvement is illusory because at 0.51 deciviews people do not perceive a regional haze problem. The difference in visibility from natural background when evaluating the baseline could have several days near the 0.5 dV "contribute to visibility degradation" threshold, but well less than the 1 dV "cause visibility degradation" threshold. Then, a very small change in visibility from the baseline to the controlled emission scenario (~0.01 – 0.1 dV) could cause a large number of days to be less than the 0.5 dV benchmark without producing any real benefit to visibility.

Hibbing Taconite (HibTac) CAMx Emissions and Modeling Results

HibTac Emissions

Unit	EPA FIP Baseline NOx Emission (TPY)	Final FIP NOx Emission (TPY)	NOx Emission Difference (TPY)	EPA FIP Baseline SO2 Emission (TPY)	Final FIP SO2 Emission (TPY)	SO2 Emission Difference (TPY)
Line 1	2,497	749	1,748	202	202	0
Line 2	2,144	643	1,500	180	180	0
Line 3	2,247	674	1,573	188	188	0
TOTAL	**6,888**	**2,066**	**4,822**	**570**	**570**	**0**

HibTac CAMx Results (By Unit)

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
2002						
Line 1	1	0.337	1	0.305	0	0.032
Line 2	2	0.287	0	0.260	2	0.027
Line 3	1	0.318	0	0.245	2	0.073
Facility Total	33	1.10	22	0.96	11	0.14
2005						
Line 1	0	0.217	0	0.158	0	0.057
Line 2	0	0.203	0	0.124	0	0.079
Line 3	0	0.223	0	0.140	0	0.083
Facility Total	14	0.85	11	0.62	3	0.23
Voyageurs						
2002						
Line 1	0	0.197	0	0.168	0	0.029
Line 2	0	0.197	0	0.159	0	0.038
Line 3	0	0.211	0	0.163	0	0.048
Facility Total	18	0.67	10	0.61	8	0.06
2005						
Line 1	0	0.126	0	0.102	0	0.024
Line 2	0	0.122	0	0.085	0	0.037
Line 3	0	0.133	0	0.103	0	0.030
Facility Total	8	0.51	5	0.36	3	0.15

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Isle Royale						
2002						
Line 1	0	0.053	0	0.047	0	0.006
Line 2	0	0.045	0	0.036	0	0.009
Line 3	0	0.046	0	0.037	0	0.009
Facility Total	0	0.16	0	0.13	0	0.03
2005						
Line 1	0	0.038	0	0.027	0	0.011
Line 2	0	0.034	0	0.022	0	0.012
Line 3	0	0.037	0	0.026	0	0.011
Facility Total	0	0.13	0	0.09	0	0.04

HibTac Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

(EPA Table C Emission Difference = 5,259 TPY NOx)[8]
(EPA Table B Emission Difference = 4,822 TPY NOx)[9]

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 98% dV
Boundary Waters	44	3.2		7	0.19
Voyageurs	21	1.7		5	0.11
Isle Royale	26	2.1		0	0.04

[8] Emission Difference Obtained from EPA Proposed FIP Table V-C.11 – Estimated Emission Reductions and Resulting Changes in Visibility Factors for Hibbing Taconite.

[9] Emission Difference Obtained from EPA Proposed FIP Table V-B.24.

Northshore Mining CAMx Emissions and Modeling Results

Northshore Emissions

Unit	EPA FIP Baseline NOx Emission (TPY)	Final FIP NOx Emission (TPY)	NOx Emission Difference (TPY)	EPA FIP Baseline SO2 Emission (TPY)	Final FIP SO2 Emission (TPY)	SO2 Emission Difference (TPY)
Power Boiler #1	676	676	0	681	681	0
Power Boiler #2	1,093	1,093	0	1,098	1,098	0
Furnace 11	386	116	270	38	38	0
Furnace 12	378	113	265	35	35	0
FURNACES	**764**	**229**	**535**	**73**	**73**	**0**
TOTAL	**2,533**	**1,998**	**535**	**1,852**	**1,852**	**0**

Northshore CAMx Results (By Unit)

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
2002						
Power Boiler #1	32	1.487	32	1.499	0	-0.012
Power Boiler #2	49	2.087	49	2.097	0	-0.010
Furnace 11	0	0.136	0	0.139	0	-0.003
Furnace 12	0	0.133	0	0.122	0	0.011
Facility Total	73	4.16	72	4.14	1	0.02
2005						
Power Boiler #1	13	0.640	13	0.654	0	-0.014
Power Boiler #2	22	0.926	23	0.911	0	0.015
Furnace 11	0	0.087	0	0.067	0	0.020
Furnace 12	0	0.082	0	0.076	0	0.006
Facility Total	51	1.67	50	1.68	1	-0.01
Voyageurs						
2002						
Power Boiler #1	1	0.196	1	0.196	0	0.000
Power Boiler #2	1	0.293	1	0.293	0	0.000
Furnace 11	0	0.016	0	0.013	0	0.003
Furnace 12	0	0.015	0	0.013	0	0.002
Facility Total	8	0.51	8	0.51	0	0.00

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Voyageurs						
2005						
Power Boiler #1	0	0.188	0	0.193	0	-0.005
Power Boiler #2	1	0.244	1	0.247	0	-0.003
Furnace 11	0	0.020	0	0.018	0	0.002
Furnace 12	0	0.021	0	0.016	0	0.004
Facility Total	6	0.47	6	0.46	0	0.01
Isle Royale						
2002						
Power Boiler #1	3	0.294	3	0.294	0	0.000
Power Boiler #2	6	0.412	6	0.408	0	0.004
Furnace 11	0	0.034	0	0.028	0	0.006
Furnace 12	0	0.037	0	0.029	0	0.008
Facility Total	16	0.75	15	0.74	1	0.00
2005						
Power Boiler #1	3	0.180	3	0.180	0	0.000
Power Boiler #2	4	0.320	4	0.322	0	-0.002
Furnace 11	0	0.036	0	0.023	0	0.013
Furnace 12	0	0.034	0	0.022	0	0.012
Facility Total	10	0.57	8	0.55	2	0.02

Northshore Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

(EPA Table C Emission Difference = 926 TPY NOx)[10]

(EPA Table B Emission Difference = 535 TPY NOx)[11]

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 98% dV
Boundary Waters	8	0.6		1	0.01
Voyageurs	4	0.3		0	0.01
Isle Royale	5	0.4		2	0.01

[10] Emission Difference Obtained from EPA Proposed FIP Table V-C.12 – Estimated Emission Reductions and Resulting Changes in Visibility Factors for Northshore Mining.

[11] Emission Difference Obtained from EPA Proposed FIP Table V-B.8; further the emission reductions in Table C exceed the FIP baseline in Table B by 142 TPY.

United Taconite (UTAC) CAMx Emissions and Modeling Results

UTAC Emissions

Unit	EPA FIP Baseline NOx Emission (TPY)	Final FIP NOx Emission (TPY)	NOx Emission Difference (TPY)[12]	EPA FIP Baseline SO2 Emission (TPY)	Final FIP SO2 Emission (TPY)[13]	SO2 Emission Difference (TPY)
Line 1	1,643	493	1,150	1,293	577	716
Line 2	3,687	1,106	2,581	2,750	1,392	1,358
TOTAL	**5,330**	**1,599**	**3,731**	**4,043**	**1,969**	**2,074**

[12]NOx emission difference was calculated using 70% emission reduction from EPA Baseline within the proposed FIP (corresponding to 1.2 lb NOx/MMBTU); to ensure maximum emission reductions were evaluated there was no change to the final FIP emissions to reflect the final FIP limit of 1.5 lb NOx/MMBTU.

[13]Final FIP SO2 Emissions were calculated using the final FIP limit of 529 lb/hr with an operating factor of 85%; this was done to maximize the emission reductions while using a reasonable operating factor

UTAC CAMx Results (By Unit)

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
2002						
Line #1	22	1.294	10	0.674	12	0.620
Line #2	45	2.744	30	1.556	15	1.189
Facility Total	76	4.22	55	2.37	21	1.85
2005						
Line #1	11	0.610	2	0.303	9	0.307
Line #2	26	1.294	15	0.678	11	0.616
Facility Total	52	2.52	34	1.57	18	0.95
Voyageurs						
2002						
Line #1	12	0.606	2	0.307	10	0.299
Line #2	26	1.452	15	0.771	11	0.681
Facility Total	42	2.10	26	1.11	16	0.99
2005						
Line #1	4	0.331	1	0.181	3	0.150
Line #2	17	0.786	6	0.446	11	0.340
Facility Total	33	1.47	14	0.76	19	0.71

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Isle Royale						
2002						
Line #1	0	0.255	0	0.117	0	0.138
Line #2	8	0.518	0	0.266	8	0.252
Facility Total	13	0.81	3	0.41	10	0.40
2005						
Line #1	0	0.163	0	0.080	0	0.083
Line #2	1	0.322	0	0.184	1	0.138
Facility Total	10	0.57	0	0.28	10	0.29

UTAC Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

(EPA Table C Emission Difference = 3,208 TPY NOx and 3,639 TPY SO2)[14]
(EPA Table B Emission Difference = 3,731 TPY NOx and 3,639 TPY SO2)[15]

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV[16]	CAMx Modeled Difference 98% dV[16]
Boundary Waters	29	1.9		20	1.40
Voyageurs	12	0.99		18	0.85
Isle Royale	14	1.16		10	0.35

[14]Emission Difference Obtained from EPA Proposed FIP Table V-C.13 – Estimated Emission Reductions and Resulting Changes in Visibility Factors for United Taconite.

[15]Emission Difference Obtained from EPA Proposed FIP Table V-B.14 (SO2) and V-B.17 (NOx) – NOx reductions are not consistent

[16]Baseline – final FIP Emission Reductions -> 3,731 TPY NOx and 2,074 TPY SO2

The United Taconite comparison table above does not provide an "apples to apples" comparison. As noted, the EPA estimated visibility benefits include more SO2 emission reductions (proposed FIP) than are included in the final FIP. This table was amended to include the revised SO2 emission reductions using EPA's apparent methodology within the proposed FIP. The EPA scalars (proposed FIP – Table V – C.9) were applied for each pollutant using the corrected emission reduction for NOx and the revised emission reduction for SO2. Then, those resultants were averaged for each of the Class I areas to obtain the amended EPA estimates below to provide for the appropriate comparison of EPA's method.

Amended UTAC Comparison of EPA Proposed FIP Visibility Improvement Estimates with CAMx Modeling Analyses

Final FIP Emission Difference = 3,731 TPY NOx and 2,074 TPY SO2

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 98% dV
Boundary Waters	22	1.6		20	1.40
Voyageurs	10	0.8		18	0.85
Isle Royale	14	1.1		10	0.35

As discussed above, the SO4 and NO3 visibility benefits were combined by EPA. The following tables provide a modeled comparison of the impacts sorted by SO4 and NO3 on a line-specific basis, then combined for both lines. The sulfate impact was derived by sorting the visibility impacts at each receptor from each scenario by maximum sulfate contribution for each line. Likewise, the nitrate impact was derived by sorting the visibility impacts at each receptor from each scenario by maximum nitrate contribution for each line. Then, the results were summed for both lines to obtain the overall UTAC impact by pollutant. In nearly all circumstances, this will overestimate the impact of the NO_X control. This is due to the impact from the sulfate reductions that drives the total visibility impact with a much smaller percentage from the nitrate reductions. When the nitrate impact is maximized by the sorting technique, the overall impact on the same day could be very small (e.g. nitrate = 0.15 dV; total = 0.20 dV) and would not show up as part of the overall visibility change (see Line 2 – 2002 Boundary Waters results).

UTAC Line 1 – Pollutant Specific Modeling Results

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
2002						
Line #1 – NO3	0	0.106	0	0.059	0	0.047
Line #1 – SO4	22	1.294	10	0.674	12	0.620
Line #1 – All	22	1.294	10	0.674	12	0.620
2005						
Line #1 – NO3	0	0.136	0	0.083	0	0.053
Line #1 – SO4	8	0.571	2	0.280	6	0.291
Line #1 – All	11	0.610	2	0.303	9	0.307
Voyageurs						
2002						
Line #1 – NO3	0	0.040	0	0.017	0	0.023
Line #1 – SO4	11	0.582	2	0.301	9	0.281
Line #1 – All	12	0.606	2	0.307	10	0.299
2005						
Line #1 – NO3	0	0.048	0	0.027	0	0.021
Line #1 – SO4	4	0.330	1	0.155	3	0.175
Line #1 – All	4	0.331	1	0.181	3	0.150
Isle Royale						
2002						
Line #1 – NO3	0	0.033	0	0.015	0	0.018
Line #1 – SO4	0	0.216	0	0.104	0	0.112
Line #1 – All	0	0.255	0	0.117	0	0.138
2005						
Line #1 – NO3	0	0.026	0	0.011	0	0.015
Line #1 – SO4	0	0.150	0	0.072	0	0.078
Line #1 – All	0	0.163	0	0.080	0	0.083

UTAC Line 2 – Pollutant Specific Modeling Results

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
2002						
Line #2 – NO3	1	0.237	0	0.090	1	0.147
Line #2 – SO4	44	2.679	28	1.547	16	1.132
Line #2 – All	45	2.744	30	1.556	15	1.189
2005						
Line #2 – NO3	1	0.195	0	0.091	1	0.104
Line #2 – SO4	25	1.196	15	0.659	10	0.539
Line #2 – All	26	1.294	15	0.678	11	0.616
Voyageurs						
2002						
Line #2 – NO3	0	0.104	0	0.031	0	0.073
Line #2 – SO4	25	1.446	15	0.768	10	0.678
Line #2 – All	26	1.452	15	0.771	11	0.681
2005						
Line #2 – NO3	0	0.083	0	0.033	0	0.050
Line #2 – SO4	16	0.773	6	0.436	10	0.337
Line #2 – All	17	0.786	6	0.446	11	0.340
Isle Royale						
2002						
Line #2 – NO3	0	0.054	0	0.018	0	0.036
Line #2 – SO4	7	0.469	0	0.245	7	0.224
Line #2 – All	8	0.518	0	0.266	8	0.252
2005						
Line #2 – NO3	0	0.046	0	0.016	0	0.030
Line #2 – SO4	1	0.319	0	0.166	1	0.153
Line #2 – All	1	0.322	0	0.184	1	0.138

UTAC Comparison of Sulfate-Specific Amended EPA Final FIP Visibility Improvement Estimates with CAMx Modeling Analyses

Final FIP Emission Difference = 2,074 TPY SO2

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 98% dV
Boundary Waters	14	1.0		22	1.29
Voyageurs	6	0.5		16	0.74
Isle Royale	8	0.6		4	0.28

UTAC Comparison of Nitrate-Specific Amended EPA Final FIP Visibility Improvement Estimates with CAMx Modeling Analyses

Final FIP Emission Difference = 3,731 TPY NOx

Class I Area	EPA Estimated Difference Days >0.5 dV	EPA Estimated Difference 98% dV		CAMx Modeled Difference Days >0.5 dV	CAMx Modeled Difference 98% dV
Boundary Waters	31	2.3		1	0.18
Voyageurs	15	1.1		0	0.08
Isle Royale	20	1.6		0	0.05

The maximum 98th percentile NO3 impact when combining both line emission reductions is 0.18 dV, while the maximum 98th percentile SO4 impact for both lines is 1.29 dV. Based on these results, it is evident that the SO4 impact on the Class I areas provides the vast majority of the predicted CAMx estimates of visibility improvement. This finding is consistent with MPCA's original finding for BART in the 2009 SIP that NOx emission reductions do not provide substantive visibility improvement.

Tilden Mining CAMx Emissions and Modeling Results

Tilden Emissions

Unit	EPA FIP Baseline NOx Emission (TPY)	Final FIP NOx Emission (TPY)	NOx Emission Difference (TPY)	EPA FIP Baseline SO2 Emission (TPY)	Final FIP SO2 Emission (TPY)	SO2 Emission Difference (TPY)
Line 1	4,613	1,384	3,229	1,153	231	922
TOTAL	**4,613**	**1,384**	**3,229**	**1,153**	**231**	**922**

Tilden CAMx Results (By Unit)

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
2002						
Line #1	0	0.141	0	0.037	0	0.104
2005						
Line #1	0	0.097	0	0.042	0	0.055
Voyageurs						
2002						
Line #1	0	0.042	0	0.011	0	0.031
2005						
Line #1	0	0.041	0	0.010	0	0.031
Isle Royale						
2002						
Line #1	1	0.300	0	0.094	1	0.206
2005						
Line #1	0	0.211	0	0.070	0	0.141

Tilden Line 1 – Pollutant Specific Modeling Results

Class I Area	EPA FIP Baseline Days >0.5 dV	EPA FIP Baseline 98% dV	Final FIP Days > 0.5 dV	Final FIP 98% dV	Difference Days >0.5 dV	Difference 98% dV
Boundary Waters						
2002						
Line #1 – NO3	0	0.031	0	0.013	0	0.018
Line #1 – SO4	0	0.102	0	0.022	0	0.080
Line #1 – All	0	0.141	0	0.037	0	0.104
2005						
Line #1 – NO3	0	0.045	0	0.042	0	0.003
Line #1 – SO4	0	0.087	0	0.019	0	0.068
Line #1 – All	0	0.097	0	0.042	0	0.055
Voyageurs						
2002						
Line #1 – NO3	0	0.002	0	0.001	0	0.001
Line #1 – SO4	0	0.041	0	0.011	0	0.030
Line #1 – All	0	0.042	0	0.011	0	0.031
2005						
Line #1 – NO3	0	0.005	0	0.003	0	0.002
Line #1 – SO4	0	0.039	0	0.008	0	0.031
Line #1 – All	0	0.041	0	0.010	0	0.031
Isle Royale						
2002						
Line #1 – NO3	0	0.084	0	0.038	0	0.046
Line #1 – SO4	1	0.197	0	0.052	1	0.145
Line #1 – All	1	0.300	0	0.094	1	0.206
2005						
Line #1 – NO3	0	0.043	0	0.047	0	-0.004
Line #1 – SO4	0	0.176	0	0.040	0	0.136
Line #1 – All	0	0.211	0	0.070	0	0.141

Attachment 3

2012 AECOM Report

AECOM

Visibility Impact of Taconite Plants in Minnesota and Michigan at PSD Class I Areas

Robert Paine and David Heinold, AECOM

September 28, 2012

Executive Summary

This report reviews several aspects of the visibility assessment that is part of any Best Available Retrofit Technology (BART) assessment. The crux of this analysis focuses upon two opportunistic emission reductions that have resulted in no perceptible visibility benefits, while a straightforward application of EPA's modeling procedures would predict a substantial visibility benefit. These actual emission reduction cases include the shutdown of the Mohave Generating Station (and minimal visibility effects at the Grand Canyon) as well as the economic slowdown that affected emissions from the taconite plants in Minnesota in 2009.

There are several reasons why there is an inconsistency between the real world and the modeling results:

- Natural background conditions, which are used in the calculation of haze impacts due to anthropogenic emissions, are mischaracterized as too clean, which exaggerates the impact of emission sources. Overly clean natural conditions can erroneously indicate that some states are missing the 2018 milestone for achieving progress toward an impossible goal by the year 2064.

- The chemistry in the current EPA-approved version of CALPUFF as well as regional photochemical models overestimates winter nitrate haze, especially with the use of high ammonia background concentrations. There are other CALPUFF features that result in overpredictions of all pollutant concentrations that are detailed in this report. Therefore, BART emission reductions will be credited with visibility modeling for more visibility improvements than will really occur. We recommend that EPA adopt CALPUFF v. 6.42, which includes substantial improvements in the chemistry formulation. We also recommend the use of seasonally varying ammonia background concentrations, in line with observations and the current capabilities of CALPUFF.

- In addition to CALPUFF, the use of regional photochemical models results in significant nitrate haze overpredictions for Minnesota Class I area predictions.

- The modeled base case modeled scenario is always a worst-case emission rate which is assumed to occur every day. The actual emissions are often lower, and so the modeled improvement is an overestimate.

Impacts of the taconite plants' NO_X emissions are confined to winter months by the unique chemistry for nitrate particle formation. During these months, the attendance at the parks is greatly reduced by the closure of significant portions of the parks and the inability to conduct boating activities on frozen water bodies. In the case of Isle Royale National Park, there is total closure in the winter, lasting for 5 ½ months. The BART rule makes a provision for the consideration of such seasonal impacts. The imposition of NO_X controls year-round would not only have minimal benefits in the peak visitation season of summer, but also could lead to increases in haze due to the increased power requirements (and associated emissions) needed for their operation, an effect that has not been considered in the visibility modeling.

An analysis of the impact of the visibility impacts of Minnesota BART sources on Michigan's Class I areas, as well as the impacts of Michigan sources on Minnesota's Class I areas indicates that the effects on the other state's Class I areas is minor. The taconite plant emissions are not expected to interfere with the ability of other states to achieve their required progress under the Regional Haze Rule.

Introduction

Best Available Retrofit Technology (BART) is part of the Clean Air Act (Appendix Y of 40 CFR Part 51) as a requirement related to visibility and the 1999 Regional Haze Rule (RHR)[1] that applies to existing stationary sources. Sources eligible for BART were those from 26 source categories with a potential to emit over 250 tons per year of any air pollutant, and that were placed into operation between August 1962 and August 1977. Final BART implementation guidance for regional haze was published in the Federal Register on July 6, 2005[2].

The United States Environmental Protection Agency (EPA) has issued a proposed rule[3] to address BART requirements for taconite plants in Minnesota and Michigan that involves emission controls for SO_2 and NO_X. This document addresses the likely visibility impact of taconite plant emissions, specifically NO_X emissions, for impacts at Prevention of Significant Deterioration (PSD) Class I areas that the RHR addresses.

Locations of Emission Sources and PSD Class I Areas

Figure 1 shows the location of BART-eligible taconite plants in Minnesota and Michigan addressed in EPA's proposed rule, as well as Class I areas within 500 km of these sources. In most applications of EPA's preferred dispersion model for visibility impacts, CALPUFF[4], the distance limitation is 200-300 km because of the overprediction tendencies[5] for further distances. The overprediction occurs because of extended travel times that often involve at least a full day, during which there can be significant wind shear influences on plume spreading that the model and the meteorological wind field does not accommodate. With larger travel distances, there are higher uncertainties in the predictions of any model, either CALPUFF or a regional photochemical model. Therefore, a reasonable upper limit for establishing the impact of the taconite sources would be 500 km, with questionable results beyond 200-300 km from the source. In this case, the Class I areas involved are those shown in Figure 1. All other PSD Class I areas are much further away. It is noteworthy that EPA's visibility improvement assessment considered only three Class I areas: Voyageurs National Park, Boundary Waters Canoe Area Wilderness, and Isle Royale National Park.

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[1] Regional Haze Regulations; Final Rule. *Federal Register*, *64*, 35713-35774. (July 1, 1999).

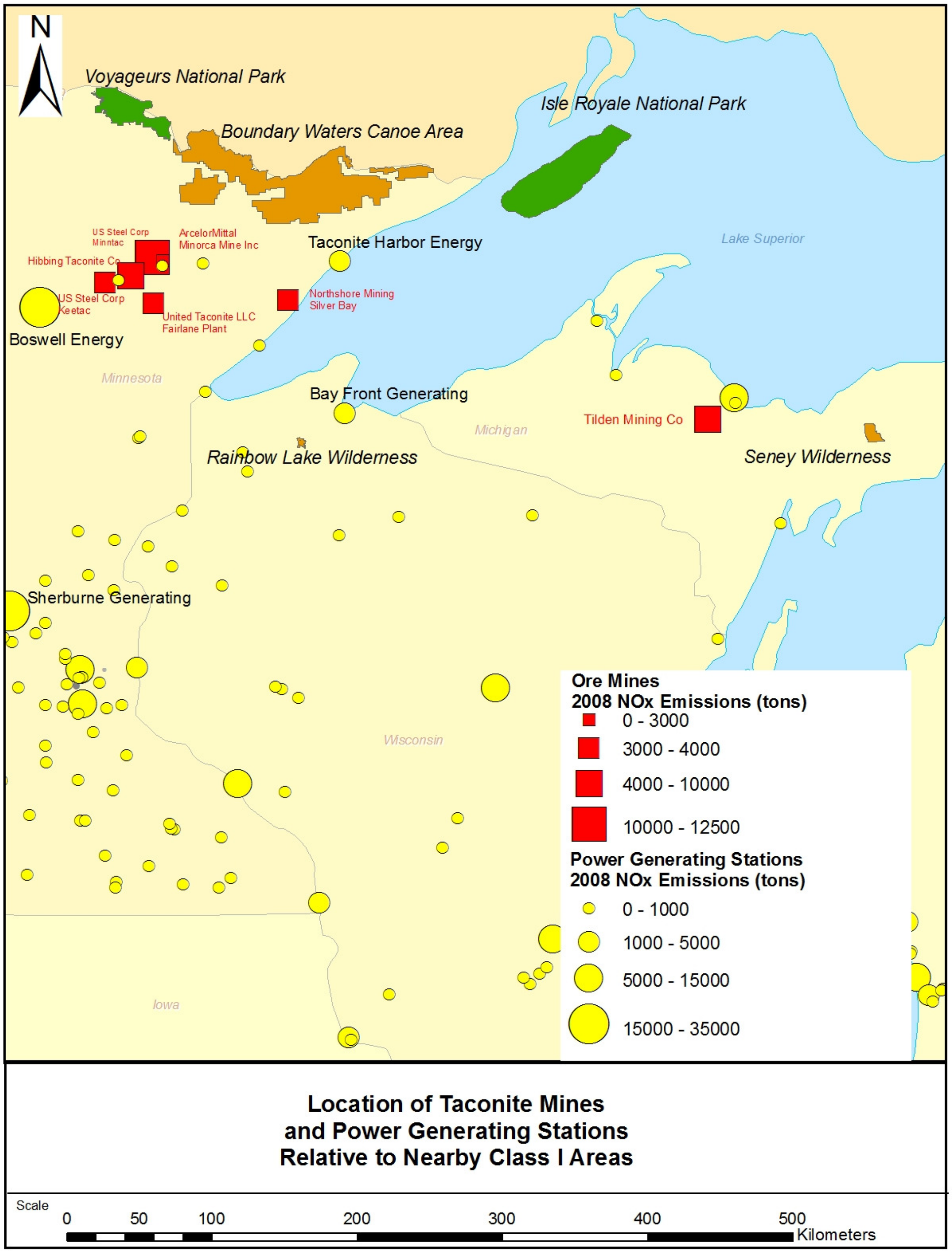
[2] Federal Register. EPA Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule. Federal Register, Vol. 70. (July 6, 2005)

[3] 77FR49308, August 15, 2012.

[4] CALPUFF Dispersion Model, 2000. http://www.epa.gov/scram001 (under 7th Modeling Conference link to Earth Tech web site).

[5] As documented in Appendix D of the IWAQM Phase 2 document, available at www.epa.gov/scram001/7thconf/calpuff/**phase2**.pdf.

Figure 1 Location of Emission Sources Relative To PSD Class I Areas in Minnesota and Michigan



Overprediction Tendency of Visibility Assessment Modeling for BART Emission Reductions

A particularly challenging part of the BART process is the lack of well-defined criteria for determining whether a proposed emission reduction is sufficient, because the criteria for determining BART are somewhat subjective in several aspects, such as what controls are cost-effective and the degree to which the related modeled reductions in haze are sufficient. In addition, the calculations of the visibility improvements, which are intrinsic to establishing the required BART controls, are subject to considerable uncertainty due both to the inherent uncertainty in model predictions and model input parameters. Alternative approaches for applying for technical options and chemistry algorithms in the United States Environmental Protection Agency's (EPA's) preferred CALPUFF model can result in a large range in the modeled visibility improvement. The degree of uncertainty is especially large when NO_X emission controls are considered as a BART option because modeling secondary formation of ammonium nitrate is quite challenging. Accurately modeling the effects of NO_X controls on visibility is very important because they are often very expensive to install and operate. As a collateral effect that needs to be taken into account for BART decisions, such controls can also complicate energy efficiency objectives and strategies to control greenhouse gases and other pollutants. In this paper we discuss why EPA's preferred application of CALPUFF would likely overestimate the predicted visibility impact of emissions, especially NO_X, and the associated effectiveness of NO_X emission controls. Overestimates of the benefits of emissions reduction are evident from the following observations, which are discussed in this document:

- Natural background extinction used in CALPOST to calculate a source's haze impacts is underestimated, which has the effect of exaggerating the impact, which is computed relative to these defined conditions. Natural conditions also dictate how well each state is adhering to the 2018 milestone for achieving progress toward this goal by the year 2064. If the specification of natural conditions is underestimated to the extent that it is not attainable regardless of contributions from U.S. anthropogenic sources, then some states will be penalized for not achieving sufficient progress toward an impossible goal. Appendix A discusses this point in more detail.

- The chemistry in the current EPA-approved version of CALPUFF overestimates winter nitrate haze, especially in conjunction with the specification of high ammonia background concentrations. This conservatism is exacerbated by CALPUFF features that result in overpredictions of all pollutant concentrations. Therefore, CALPUFF modeling will credit BART emission reductions with more visibility improvements than will really occur.

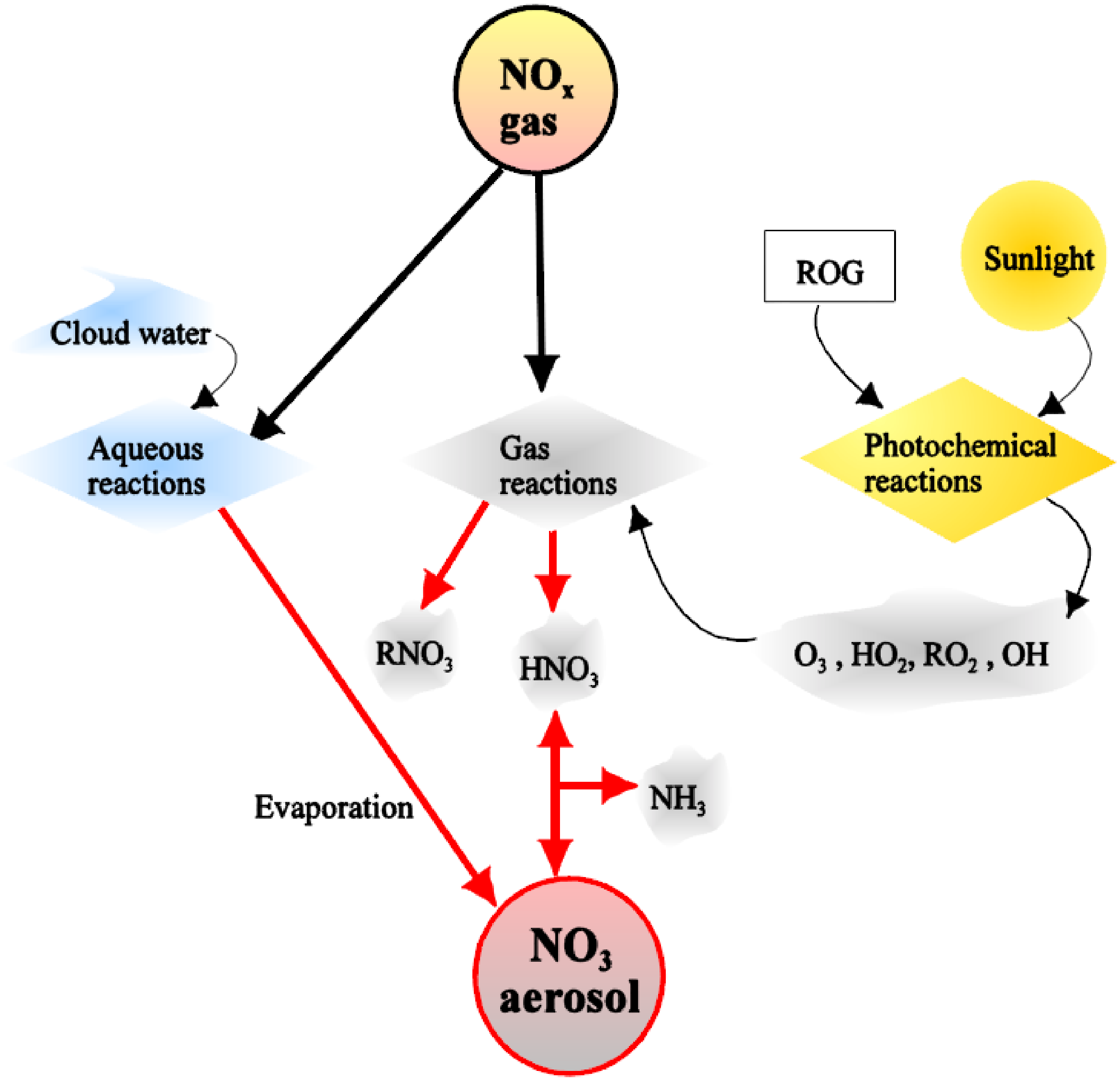
- There are examples where actual significant emission reductions have occurred, where CALPUFF modeling as conducted for BART would predict significant visibility improvements, but no perceptive changes in haze occurred.

Visibility Impact of NO_X Emissions – Unique Aspects and Seasonality

The oxidation of NO_X to total nitrate (TNO_3) depends on the NO_X concentration, ambient ozone concentration, and atmospheric stability. Some of the TNO_3 is then combined with available ammonia in the atmosphere to form ammonium nitrate aerosol in an equilibrium state with HNO_3 gas that is a function

of temperature, relative humidity, and ambient ammonia concentration, as shown in Figure 2[6]. It is important to realize that both CALPUFF and regional photochemical models tend to overpredict nitrate formation, especially in winter. A more detailed discussion of this issue is provided in Appendix B.

Figure 2 CALPUFF II NO_x Oxidation



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[6] Figure 2-32 from CALPUFF Users Guide, available at http://www.src.com/calpuff/download/CALPUFF_UsersGuide.pdf.

In CALPUFF, total nitrate ($TNO_3 = HNO_3 + NO_3$) is partitioned into each species according to the equilibrium relationship between gaseous HNO_3 and NO_3 aerosol. This equilibrium is a function of ambient temperature and relative humidity. Moreover, the formation of nitrate strongly depends on availability of NH_3 to form ammonium nitrate. A summary of the conditions affecting nitrate formation is provided below:

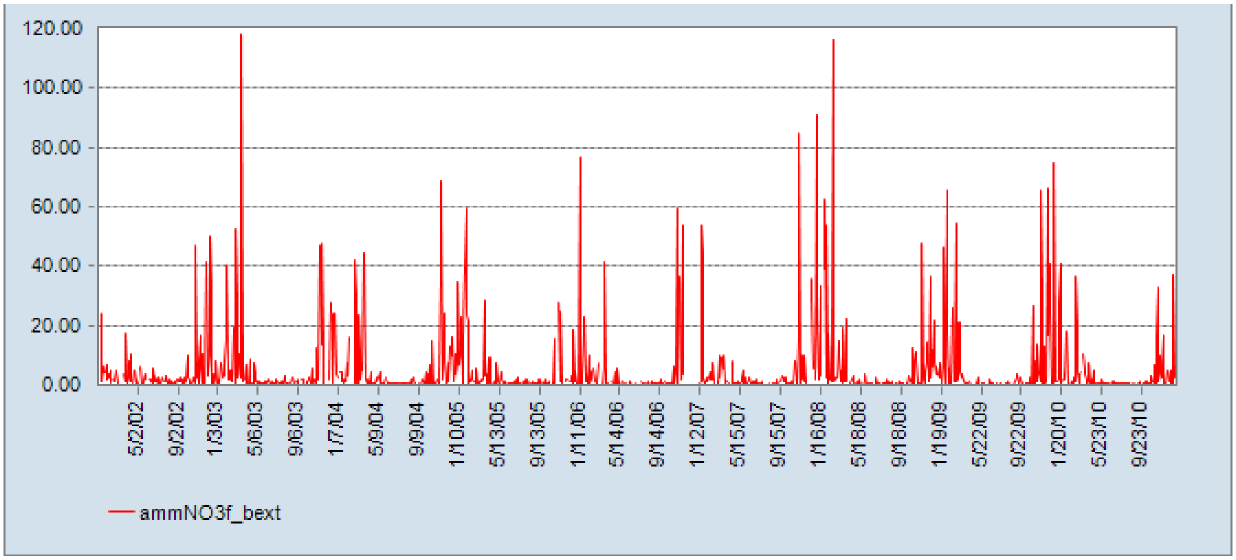
- Colder temperature and higher relative humidity create favorable conditions to form nitrate particulate matter, and therefore more ammonium nitrate is formed;
- Warm temperatures and lower relative humidity create less favorable conditions to form nitrate particulate matter, and therefore less ammonium nitrate is formed;
- Sulfate preferentially scavenges ammonia over nitrates.

For this BART analysis, the effects of temperature and background ammonia concentrations on the nitrate formation are the key to understanding the effects of various NO_X control options. For parts of the country where sulfate concentrations are relatively high and ammonia emissions are quite low, the atmosphere is likely to be in an ammonia-limited regime relative to nitrate formation. Therefore, NO_X emission controls are not very effective in improving regional haze, especially if there is very little ambient ammonia available.

In many cases, the BART visibility assessments ignore the haze increases that occur due to the additional power generation required to operate the control equipment. For NO_X controls, for example, the warm season emissions have minimal visibility impact, but the associated SO_2 emissions from the power generation required to run the controls will increase sulfate haze. These effects have not been considered in the visibility assessment modeling.

It is evident from haze composition plots available from Interagency Monitoring of Protected Visual Environments (IMPROVE) monitors that nitrate haze is confined to winter months. This is clearly shown in Figure 3, which is a timeline of nitrate haze extinction from Boundary Waters Canoe Area Wilderness. Similar patterns are evident for the other Class I areas plotted in Figure 1. The impact of NO_X emissions during the non-winter months (e.g., April through October) is very low.

Figure 3 Boundary Water Canoe Area Wilderness Ammonium Nitrate Extinction, 2002-2010



The occurrence of significant nitrate haze only in the winter months has implications for the effectiveness of haze reductions relative to park attendance. The BART Rule addresses the seasonal issue as follows: "Other ways that visibility improvement may be assessed to inform the control decisions would be to examine distributions of the daily impacts, determine if the time of year is important (e.g., high impacts are occurring during tourist season) . . ."

In this case, the high nitrate impacts are not occurring during the tourist season, especially for the water-dominant Class I areas in Minnesota (Voyageurs and Boundary Waters) that freeze in winter. In fact, for Voyageurs National Park, the typical monthly attendance[7] for an off-season month (November) is only 0.2% that of a peak-season month (July). This is obviously due in part to the brutal winter weather in northern Minnesota (and Michigan) and the lack of boating access to frozen water bodies.

Operations at the Michigan Class I areas in winter are even more restricted. Isle Royale National Park is one of the few national parks to totally close[8] during the winter (generally, during the period of November 1 through April 15). The closure is due to the extreme winter weather conditions and difficulty of access from the mainland across a frozen Lake Superior, for the protection of wildlife, and for the safety and protection of potential visitors. Due to this total closure, there is very little nitrate haze impact in this park during the seasons of the year that it is open, and haze issues for Isle Royale National Park will not be further considered in this report.

The Seney Wilderness Area Visitor Center is open[9] only during the period of May 15th to mid-October. Various trails are generally only open during the same period. The tour loops are closed in the fall, winter, and spring to allow migrating and nesting birds a place to rest or nest undisturbed, and because of large amounts of snow. Although portions of the park are open in the winter, the visitation is greatly reduced due to no visitor center access, no trail or tour loop access, and the severe weather.

Effect of 2009 Recession on Haze in Affected PSD Class I Areas

The effect on haze of a significant (50%) emission reduction from the taconite plants that actually occurred in early 2009 and lasted throughout calendar year 2009 is discussed in this section. This emission reduction was not due to environmental regulations, but rather economic conditions, and affected all pollutants being emitted by the collective group of Minnesota taconite plants, as well as regional power production that is needed to operate the taconite plants.

The annual taconite production[10] from the Minnesota taconite plants in recent years is plotted in Figure 4, along with annual average nitrate concentrations at the nearest Class I area, Boundary Waters Canoe Area (BWCA). The figure shows that the nitrate measured in the park did not respond to the reduction in emissions from the taconite plants. Figures 5 and 6 show the time series[11] of nitrate and sulfate haze in

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[7] As documented at http://www.gorp.com/parks-guide/voyageurs-national-park-outdoor-pp2-guide-cid9423.html.

[8] As noted at http://www.nps.gov/isro/planyourvisit/hours.htm.

[9] As noted at http://www.fws.gov/midwest/seney/visitor_info.html.

[10] Production data is available from taxes levied on taconite production, and the data was supplied by BARR Engineering through a personal communication with Robert Paine of AECOM.

[11] Available from the VIEWS web site at http://views.cira.colostate.edu/web/.

the BWCA over the past several years. Figures for other affected Class I areas (Voyageurs, Seney, and Isle Royale) are shown in Appendix C.

Figure 4 Minnesota Taconite Production and BWCA Nitrate Concentrations

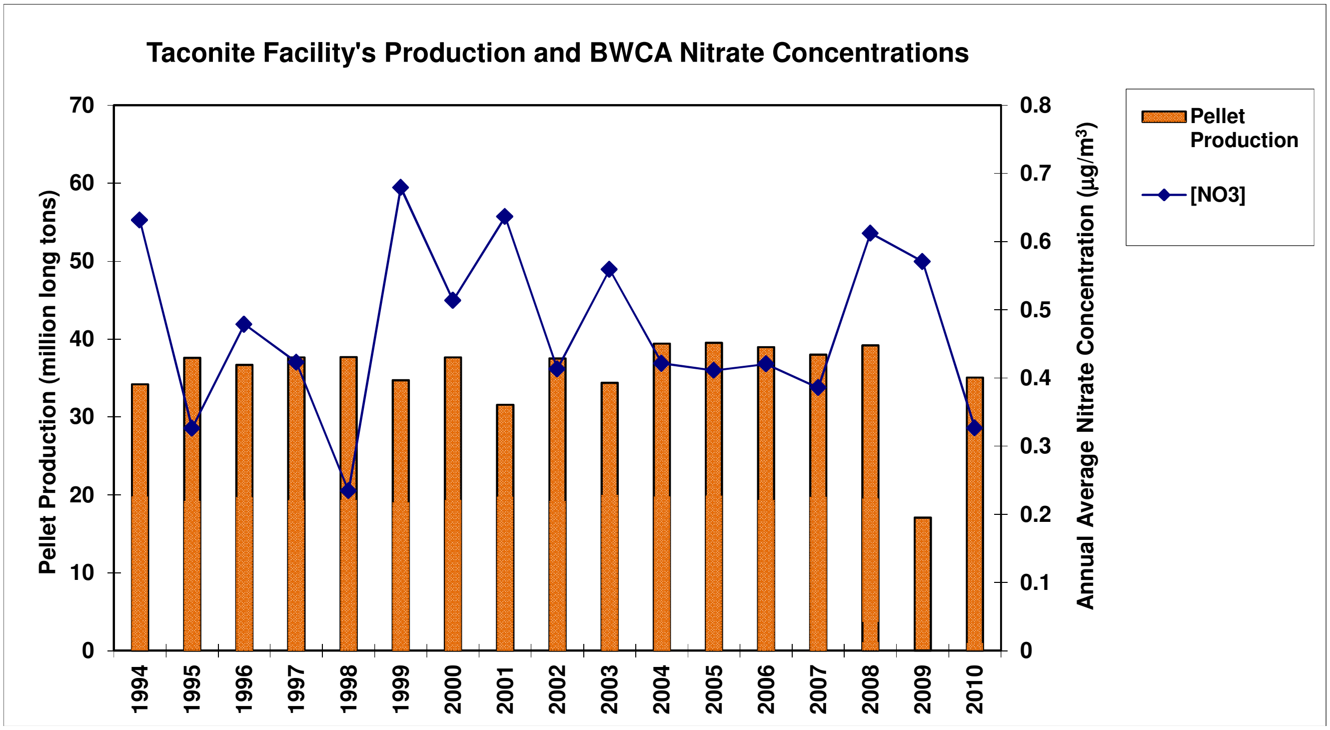


Figure 5 Time Series of Nitrate Haze at Boundary Waters Canoe Area (2002-2010)

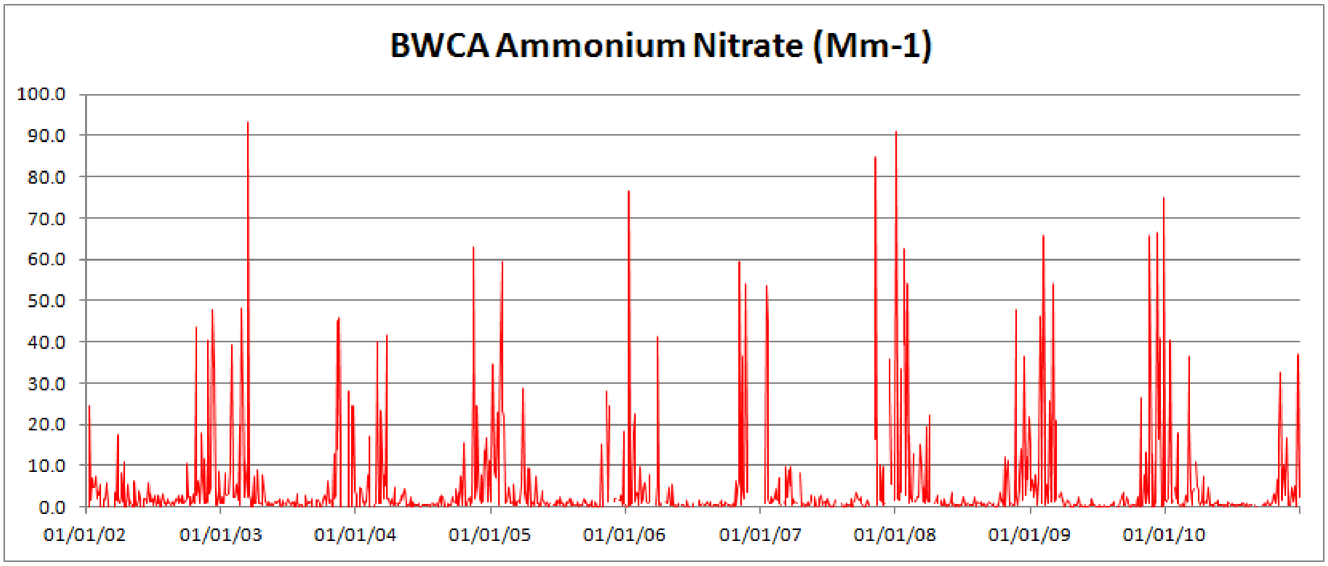
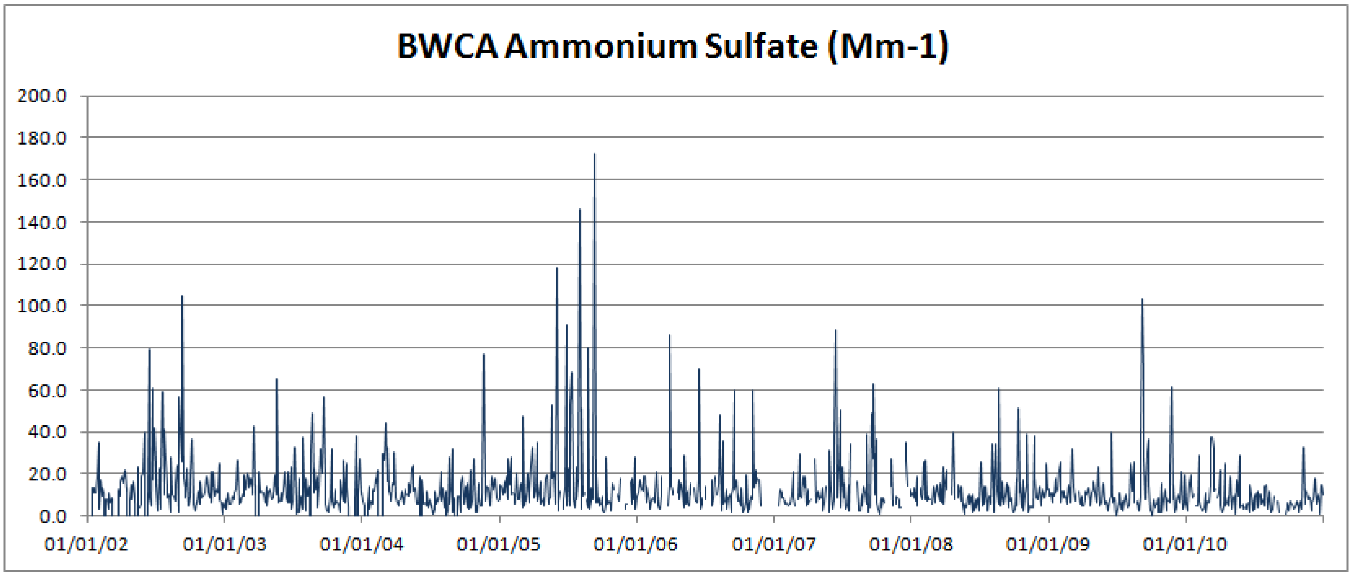


Figure 6 Time Series of Sulfate Haze at Boundary Waters Canoe Area (2002-2010)



It is evident from this information that the haze levels in BWCA did not, in general, decrease during 2009, and were therefore unaffected by emission reductions associated with the taconite production slowdown. It is noteworthy that peak events during mid-2009 in sulfate haze at BWCA when very little taconite production was occurring clearly indicate that minimal haze reduction would likely be associated with taconite plant emission reductions.

It is instructive to review the haze composition time series plots for BWCA for 2008, 2009, and 2010, as shown in Figures 7, 8, and 9.

Figure 7 Haze Composition Figure for Boundary Waters Canoe Area Wilderness, 2008

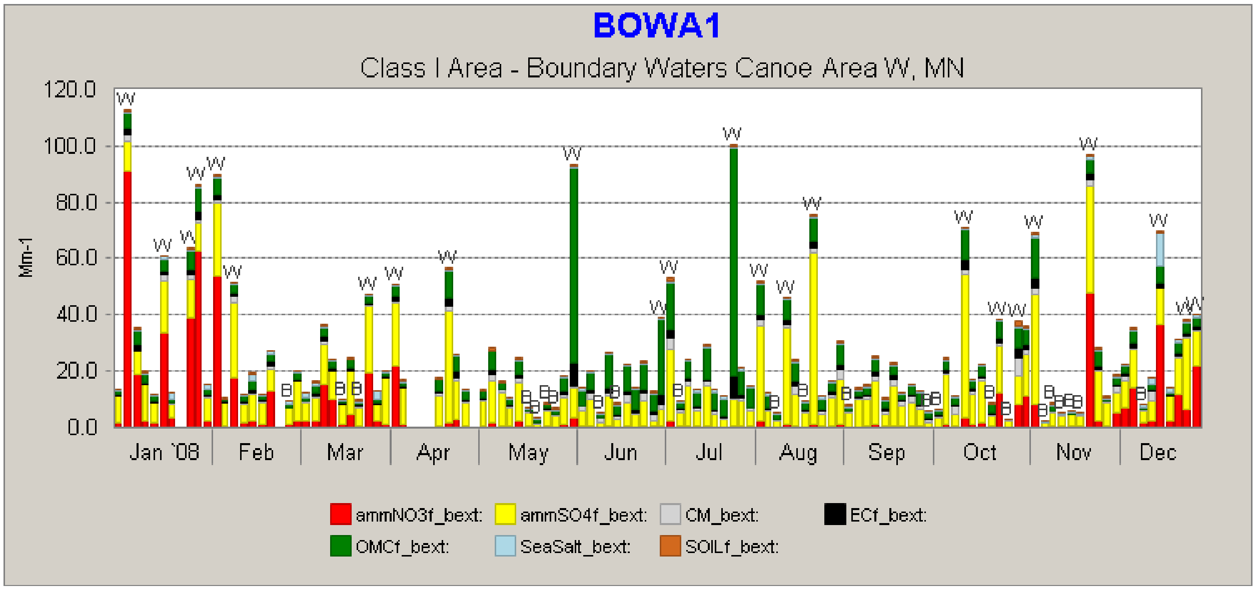


Figure 8 Haze Composition Figure for Boundary Waters Canoe Area Wilderness, 2009

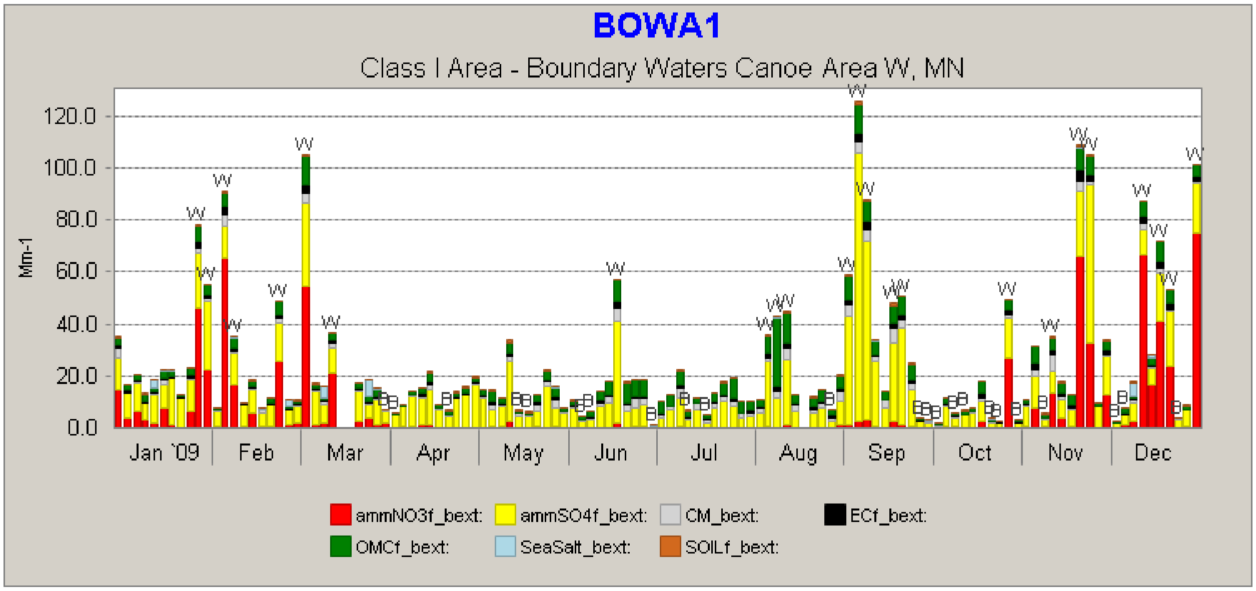
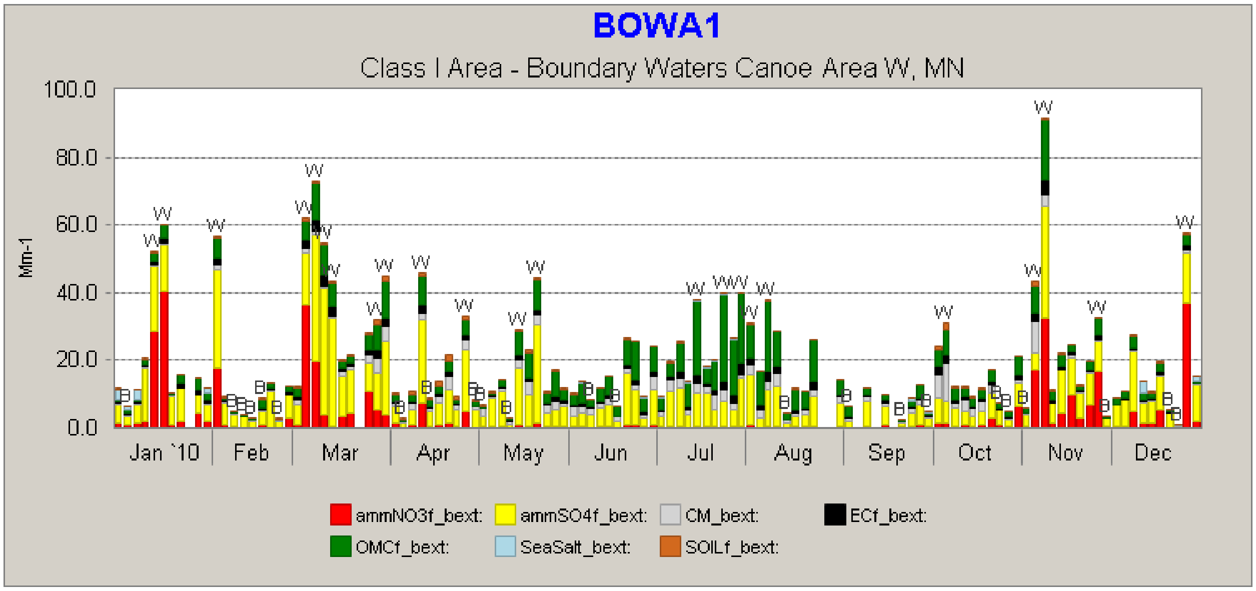


Figure 9 Haze Composition Figure for Boundary Waters Canoe Area Wilderness, 2010



As has been mentioned above, it is evident that the nitrate haze (red bars) is only important during the colder months (November through March). It is also evident that haze from forest fires (green bars) is predominant in the warm weather months, but varies from year to year according to the frequency of wildfires. For example, 2008 was a year of high occurrences of wildfires, while 2009 saw a low frequency, and 2010 was more normal.

The curtailment of taconite plant activity lasted from early 2009 through December 2009, peaking in the summer of 2009. Even so, we see the highest sulfate haze days (yellow bars) in September 2009 when taconite production was half of normal activity. Also, we note high nitrate haze days late in 2009 with the taconite plant curtailment that are comparable in magnitude to full taconite production periods in 2008. We also note that after the taconite plants went back to full production in 2010, the haze levels dropped, apparently due to emissions from other sources and/or states.

These findings suggest that reduction of emissions from the taconite plants will likely have minimal effects on haze in the nearby Class I areas. The fact that the various plants are distributed over a large area means that individual plumes are isolated and generally do not combine with others.

At least one other emission reduction opportunity to determine the effect on visibility improvement has occurred; this is related to the shutdown of the Mohave Generating Station in 2005, and its effect upon visibility in the Grand Canyon National Park. The discussion in Appendix D indicates that although CALPUFF modeling predicted substantial visibility benefits, very little change has occurred since 2005.

Other reasons that visibility assessment models such as CALPUFF could overpredict impacts are listed below.

1) The CALPUFF base case modeled scenario is always a worst-case emission rate which is assumed to occur every day. The actual emissions are often lower, and so the modeled improvement is an overestimate.

2) The way that the predicted concentrations are accounted for in the CALPOST output overstate the impact for even the case where the CALPUFF predictions are completely accurate. The way that CALPOST works is that the peak 24-hour prediction <u>anywhere</u> in a Class I area is the only information saved for each predicted day. The predicted impact for each day is effectively assumed to be a) always in the same place; and b) in all portions of the Class I area. Therefore, the 98th percentile day's prediction could be comprised of impacts in 8 different places that are all erroneously assumed to be co-located.

3) CALPUFF does not simulate dispersion and transport accurately over a full diurnal cycle, during which significant wind direction shear can occur (and is not properly accounted for by CALPUFF). This can result in plumes that are more cohesive than actually occur.

4) As discussed above, it is well established that nitrate predictions are often overstated by CALPUFF v. 5.8, especially in winter.

5) Natural conditions as input to CALPOST are not attainable, and their use will exaggerate the simulated visibility impacts of modeled emissions.

<u>Interstate Non-Interference with Regional Haze Rule SIPs from Taconite Plant Emissions</u>

An issue that is a recurring one for a number of state implementation plans (SIPs) is whether emissions from one state can interfere with haze reduction plans for downwind states. For Minnesota, it would be expected that emission reductions undertaken to reduce haze in Minnesota Class I areas (Voyageurs and Boundary Waters) would also act to reduce haze in other Class I areas. In the case of Minnesota's

taconite plant emissions, earlier discussions of the potentially affected Class I areas indicated that only the Class I areas in northern Michigan (Isle Royale National Park and Seney Wilderness Area) are close enough and in a general predominant wind direction to merit consideration. The closer of these two parks, Isle Royale, is closed to the public from November 1 through April 15, and haze effects there would not be affected by NO_X emissions because those effects are only important in the winter. Since Minnesota's Class I areas are located generally upwind of Michigan sources, the impact of Michigan sources on these Class I areas is expected to be small. This is confirmed in the Particulate Matter Source Apportionment Technology (PSAT) plots shown below.

Regional photochemical modeling studies[12] conducted by the CENRAP Regional Planning Organization, of which Minnesota is a part, shows contributions of various states as well as international contributions for haze impacts in the Michigan Class I areas. Relevant figures from the Iowa RHR SIP report for 2018 emission inventory haze impacts are reproduced below for Isle Royale National Park (Figure 10) and Seney Wilderness Area (Figure 11).

The modeling conducted for this analysis, using CAMx, shows that the relative contribution to haze for all Minnesota sources to sulfate haze in Isle Royale National Park is low, consisting of only 10% of the sulfate haze. The effect of 2018 emissions from Minnesota sources at the more distant Seney Wilderness Area is even lower, with the state's emissions ranking 9th among other jurisdictions analyzed for this Class I area. Therefore, it is apparent that Minnesota sources, and certainly the subset including taconite plants, would not be expected to interfere with other state's progress toward the 2018 milestone associated with the Regional Haze Rule.

Figures 12 and 13, reproduced from the Iowa RHR SIP report for Boundary Waters and Voyageurs, respectively, indicate that Michigan sources rank 11th and 12th, respectively, for haze impacts in these two areas for projected 2018 emissions. Therefore, as expected, Michigan sources are not expected to interfere with Minnesota's RHR SIP for progress in 2018.

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[12] See, for example, the Iowa State Implementation Plan for Regional Haze report at http://www.iowadnr.gov/portals/idnr/uploads/air/insidednr/rulesandplanning/rh_sip_final.pdf, Figures 11.3 and 11.4.

Figure 10 PSAT Results from CENRAP CAMx Modeling for Isle Royale National Park

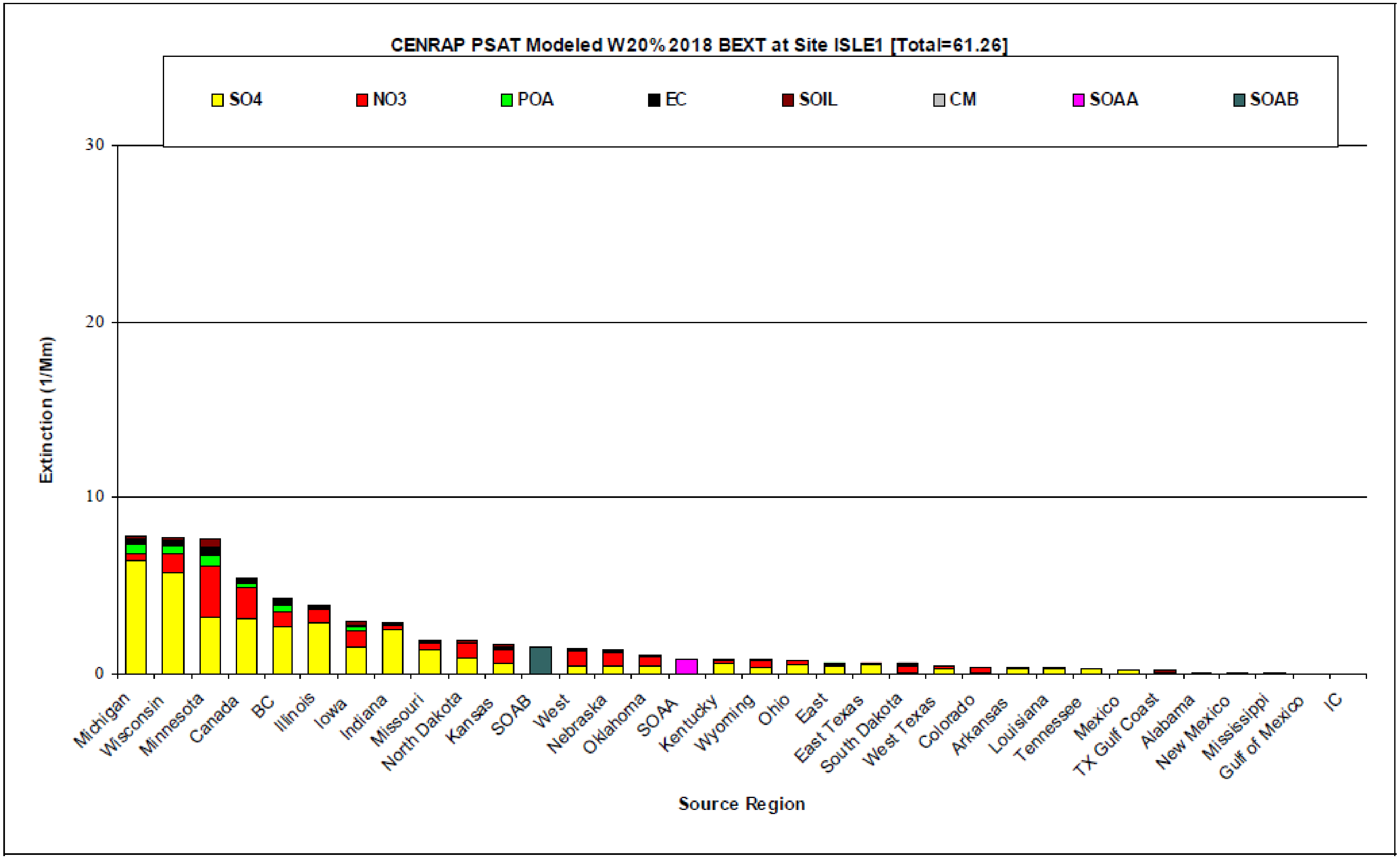


Figure 11.3. Source apportion contributions by region and pollutant to ISLE in 2018.

Figure 11 PSAT Results from CENRAP CAMx Modeling for Seney Wilderness Area

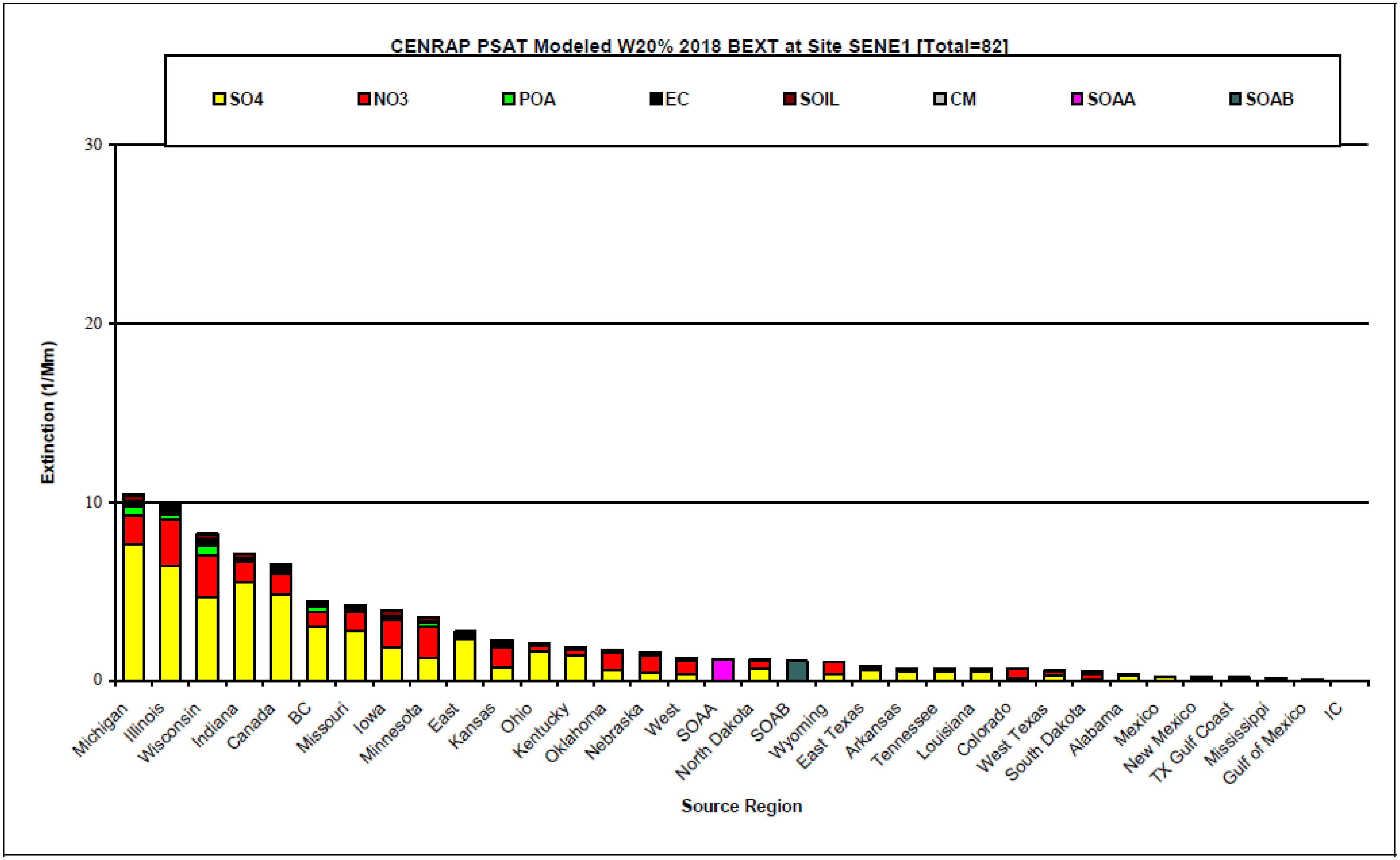


Figure 11.4. Source apportion contributions by region and pollutant to SENE in 2018.

Figure 12 PSAT Results from CENRAP CAMx Modeling for Boundary Waters Canoe Area Wilderness

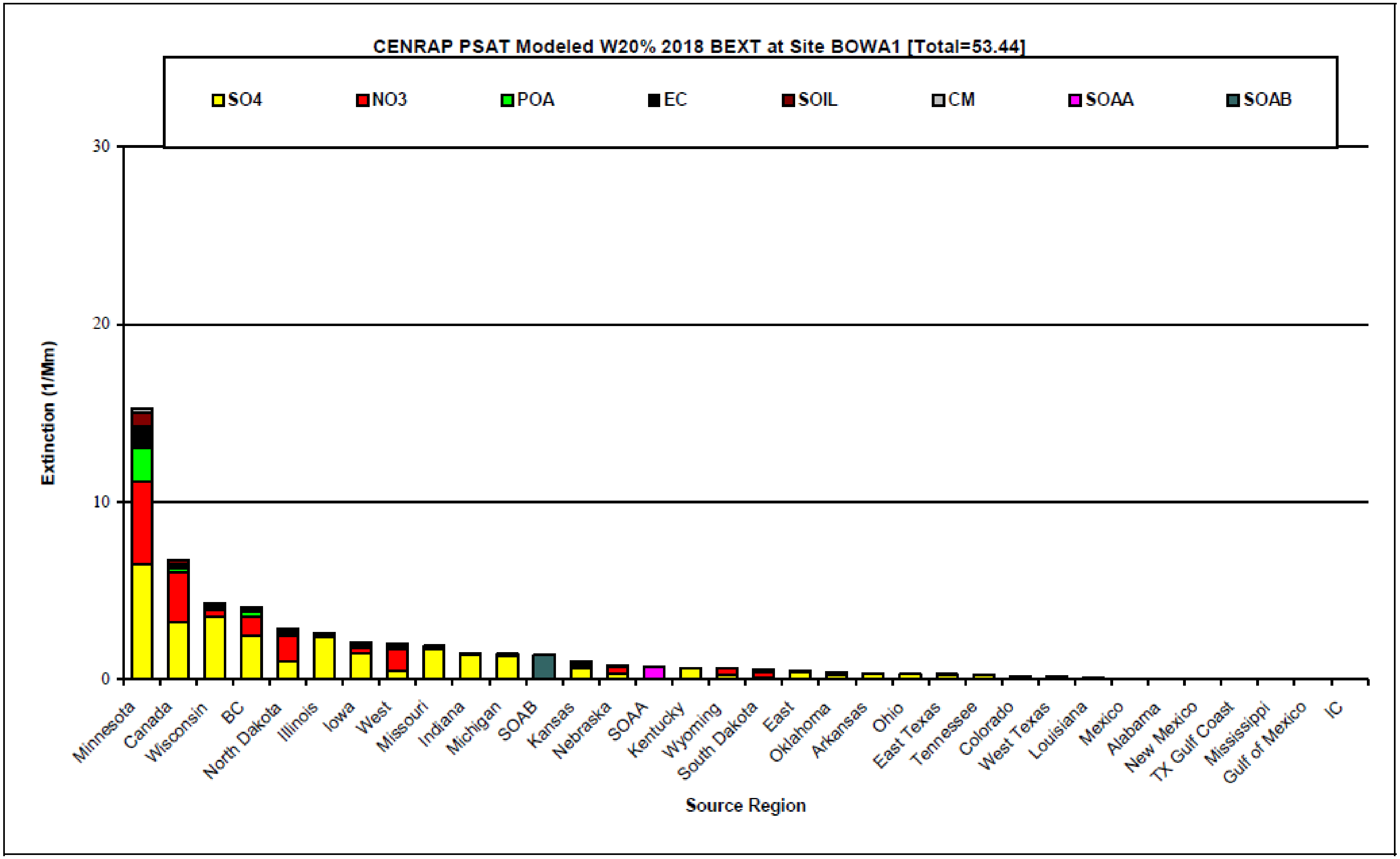


Figure 11.1. Source apportion contributions by region and pollutant to BOWA in 2018.

Figure 13 PSAT Results from CENRAP CAMx Modeling for Voyageurs National Park

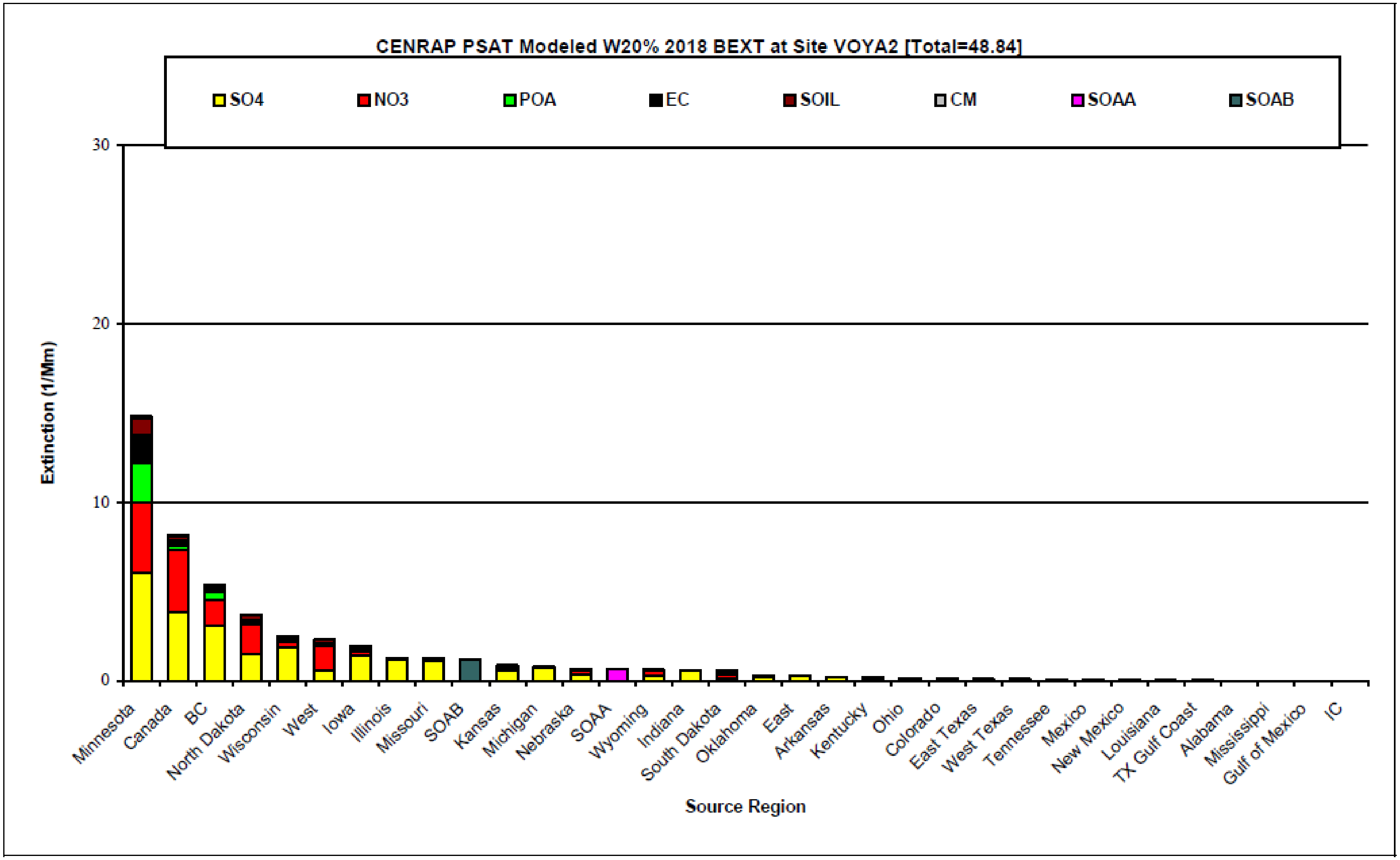


Figure 11.2. Source apportion contributions by region and pollutant to VOYA in 2018.

CONCLUSIONS

EPA's preferred modeling tools to assess the visibility improvement from BART controls will likely overestimate the predicted visibility improvement. While this is expected for all pollutants, it is especially true for NO_X emission controls. This occurs for several reasons:

- Natural background conditions, which are used in the calculation of haze impacts due to anthropogenic emissions, are mischaracterized as too clear, which exaggerates the impact of emission sources. Overly clean natural conditions can lead to the erroneous conclusion that some states are not adhering to the 2018 milestone because they need to achieve progress toward an impossible goal by the year 2064.
- The chemistry in the current EPA-approved version of CALPUFF as well as regional photochemical models overestimates winter nitrate haze, especially with the use of high ammonia background concentrations. There are other CALPUFF features that result in overpredictions of all pollutant concentrations. Therefore, BART emission reductions will be credited with visibility modeling for more visibility improvements than will really occur. We recommend that EPA adopt CALPUFF v. 6.42, which includes substantial improvements in the chemistry formulation. We also recommend the use of seasonally varying ammonia background concentrations, in line with observations and the current capabilities of CALPUFF.
- In addition to CALPUFF, the use of regional photochemical models results in significant nitrate haze overpredictions for Minnesota Class I area predictions.
- The modeled base case scenario is always a worst-case emission rate, assumed to occur every day. The actual emissions are often lower, and so the modeled improvement is an overestimate.

Impacts of the taconite plants' NO_X emissions are confined to winter months by the unique chemistry for nitrate particle formation. During these months, the attendance at the parks is greatly reduced by the closure of significant portions of the parks and the inability to conduct boating activities on frozen water bodies. In the case of Isle Royale National Park, there is total closure in the winter, lasting for 5 ½ months. The BART rule makes a provision for the consideration of such seasonal impacts. The imposition of NO_X controls year-round would not only have minimal benefits in the peak visitation season of summer, but also could lead to visibility disbenefits due to the increased power requirements (and associated emissions) needed for their operation, an effect that has not been considered in the visibility modeling.

Evidence of models' tendency for overprediction are provided in examples of actual significant emission reductions that have resulted in virtually no perceptive changes in haze, while visibility assessment modeling as conducted for BART would predict significant visibility improvements. These examples include the shutdown of the Mohave Generating Station (and minimal visibility effects at the Grand Canyon) as well as the economic slowdown that affected emissions from the taconite plants in 2009.

An analysis of the impact of the visibility impacts of Minnesota BART sources on Michigan's Class I areas, and vice versa indicates that the effects on the other state's Class I areas is minor. The taconite plant emissions are not expected to interfere with the ability of other states to achieve their required progress under the Regional Haze Rule.

APPENDIX A

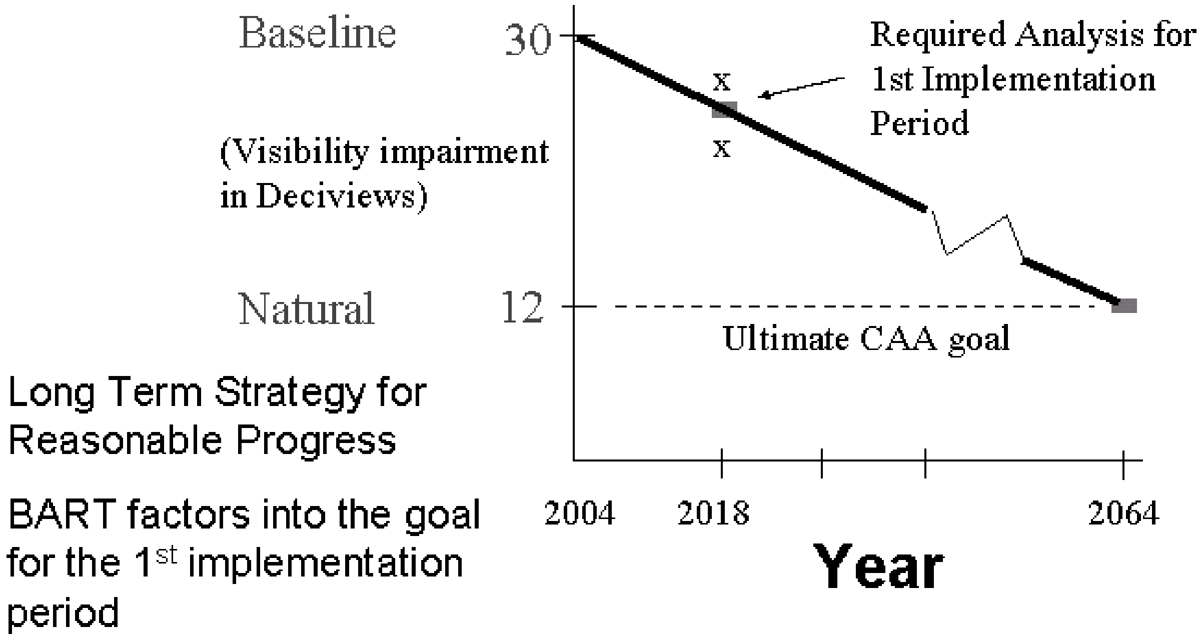
THE REGIONAL HAZE RULE GOAL OF NATURAL CONDITIONS

An important consideration in the ability for a state to meet the 2018 Uniform Rate of Progress (URP) goal is the definition of the end point goal of “natural conditions” for the worst 20% haze days; see Figure A-1, which illustrates this concept). Note that while achieving improved visibility for the worst 20% haze days, the RHR also stipulates that there should not be deterioration of visibility for the best 20%, or clearest, days. One way to define that goal would be the elimination of all man-made emissions. This raises some other questions, such as:

- To what categories of emissions does the RHR pertain?
- Does the current definition of natural conditions include non-anthropogenic or uncontrollable emissions?

The default natural background assumed by EPA in their 2003 guidance document[13] is not realistic. The discussion in this section explains why EPA’s default natural conditions significantly understate the true level of natural haze, including the fact that there are contributors of haze that are not controllable (and that are natural) that should be included in the definition of natural visibility conditions. In addition, one important aspect of the uncontrollable haze, wildfires, is further discussed regarding the biased quantification of its contribution to natural haze due to suppression of wildfires during the 20th century.

Figure A-1: Illustration of the Uniform Rate of Progress Goal



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[13] *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule*, (U.S. Environmental Protection Agency, September 2003). http://www.epa.gov/ttncaaa1/t1/memoranda/rh_envcurhr_gd.pdf.

In its RHR SIP, North Dakota[14] noted in Section 9.7 that,

"Achieving natural conditions will require the elimination of all anthropogenic sources of emissions. Given current technology, achieving natural conditions is an impossibility. Any estimate of the number of years necessary to achieve natural visibility conditions would require assumptions about future energy sources, technology improvements for sources of emissions, and every facet of human behavior that causes visibility impairing emissions. The elimination of all SO_2 and NO_x emissions in North Dakota will not achieve the uniform rate of progress for this [2018], or any future planning period. Any estimate of the number of years to achieve natural conditions is questionable because of the influence of out-of-state sources."

It will be extremely difficult, if not impossible, to eliminate all anthropogenic emissions, even if natural conditions are accurately defined. It will be even more daunting to try to reach the goal if natural conditions are significantly understated, and as a result, states are asked to control sources that are simply not controllable. It is clear that the use of EPA default natural conditions leads to unworkable and absurd results for one state's (North Dakota's) ability to determine the rate of progress toward an unattainable goal. The definition of natural conditions that can be reasonably attained for a reasonable application of USEPA's Regional Haze Rule should be revised for all states.

The objective of the following discussion is to summarize recent modeling studies of natural visibility conditions and to suggest how such studies can be used in evaluating the uniform rate of progress in reducing haze to attain natural visibility levels. In addition, the distinction between natural visibility and policy relevant background visibility is discussed. Treatment of this issue by other states, such as Texas, is also discussed.

Regional Haze Issues for Border States

There are similarities between the Regional Haze Rule (RHR) challenges for border states such as North Dakota and Texas in that both states have significant international and natural contributions to regional haze in Class I areas in their states. The Texas Commission on Environmental Quality (TCEQ) has introduced alternative RHR glide paths to illustrate the State's rate of progress toward the RHR goals. Since TCEQ has gone through the process of a RHR State Implementation Plan (SIP) development and comment period, it is instructive to look at the TCEQ approach, the comments provided by the Federal Land Managers to TCEQ, and TCEQ's reaction to the comments.

Similarities to be considered for the RHR SIP development in border states, such as North Dakota and Texas, include the items listed below.

- These states have Class I areas for which a considerable fraction of the regional haze is due to international transport or transport from other regions of the United States.

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[14] North Dakota Dep. of Health, 2010. North Dakota State Implementation Plan for Regional Haze. http://www.ndhealth.gov/AQ/RegionalHaze/Regional%20Haze%20Link%20Documents/Main%20SIP%20Sections%201-12.pdf.
.

- As a result, there is a substantial reduction in SO_2 and NO_x emissions from the BART-eligible sources in each state, but this reduction results in a relatively small impact on regional haze mitigation. Additional emission reductions would, therefore, have a minimal benefit on visibility improvement at substantial cost.

- In the Regional Haze SIP development, these states have attempted to account for the effects of anthropogenic emissions that they can control in alternative analyses. These analysis result in a finding that the in-state emission reductions come closer to meeting the Uniform Rate of Progress glide path goals for 2018. However, due to the low probability of impact of these sources on the worst 20% days, the effectiveness of in-state emission controls on anthropogenic sources subject to controls is inherently limited.

TCEQ decided that coarse and fine PM measured at the Class I areas were due to natural causes (especially on the worst 20% days), and adjusted the natural conditions endpoint accordingly. The Federal Land Managers (FLMs) agreed with this approach for the most part[15], but suggested that 80% of these concentrations would be due to natural causes, and 20% would be due to anthropogenic causes. TCEQ determined from a sensitivity analysis that the difference in these two approaches was too small to warrant a re-run of their analysis, but it is important that the FLMs agreed to a state-specific modification of the natural conditions endpoint, and this substantially changed the perceived rate of progress of the SIP plan toward the altered natural conditions endpoint.

Although the TCEQ did not address other particulate matter components in this same way, a review of air parcel back trajectories previously available from the IMPROVE web site (http://views.cira.colostate.edu/web/) suggests that other components, such as organic matter due to wildfires, could be substantially due to natural causes, so that this component should also be considered as at least partially natural.

The TCEQ discussed the issue of how emissions from Mexico could interfere with progress on the RHR, but they did not appear to adjust the glide path based upon Mexican emissions. On the other hand, in its weight of evidence analysis, North Dakota did evaluate adjustments based upon anthropogenic emissions that could not be controlled from Canadian sources, but did not take into account any specific particulate species that are generally not emitted by major anthropogenic sources of SO_2 and NO_X.

Natural Haze Levels

The Regional Haze Rule establishes the goal that natural visibility conditions should be attained in Federal Class I areas by the year 2064. Additionally, the states are required to determine the uniform rate of progress (URP) of visibility improvement necessary to attain the natural visibility goal by 2064. Finally, each state must develop a SIP identifying reasonable control measures that will be adopted well before 2018 to reduce source emissions of visibility-impairing particulate matter (PM) and its precursors (SO_2 and NO_x).

Estimates of natural haze levels have been developed by the EPA for visibility planning purposes and are described in the above-referenced EPA 2003 document. The natural haze estimates were based on ambient data analysis of selected PM species for days with good visibility and are shown in Table A-1.

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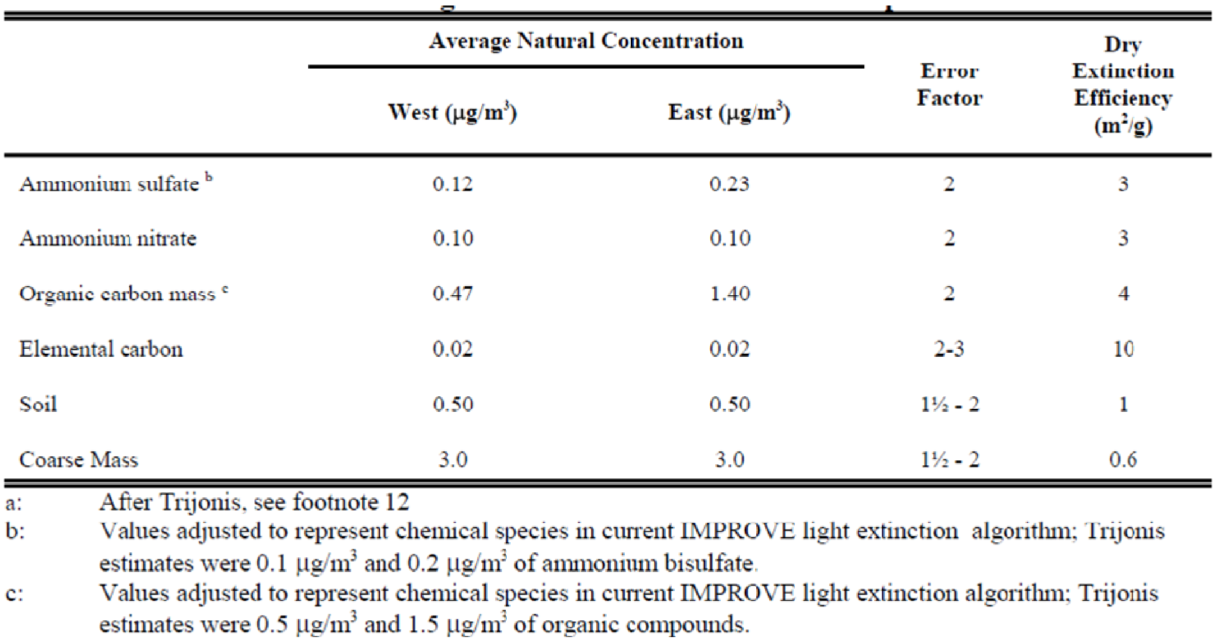
[15] See Appendix 2-2 at http://www.tceq.state.tx.us/implementation/air/sip/bart/haze_appendices.html.

These estimates were derived from Trijonis[16] and use two different sets of natural concentrations for the eastern and western U.S. Tombach[17] provides a detailed review and discussion of uncertainty in the USEPA natural PM estimates. Natural visibility can be calculated using the IMPROVE equation which calculates the light scattering caused by each component of PM. After much study, changes in the IMPROVE equation and in the method for calculating natural visibility were developed in 2005 and are described by Pitchford et al.[18]

Table A-1: Average Natural Levels of Aerosol Components from Table 2-1 of *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule* (EPA, 2003)



	Average Natural Concentration		Error Factor	Dry Extinction Efficiency (m^2/g)
	West (µg/m^3)	East (µg/m^3)		
Ammonium sulfate[b]	0.12	0.23	2	3
Ammonium nitrate	0.10	0.10	2	3
Organic carbon mass[c]	0.47	1.40	2	4
Elemental carbon	0.02	0.02	2-3	10
Soil	0.50	0.50	1½ - 2	1
Coarse Mass	3.0	3.0	1½ - 2	0.6

a: After Trijonis, see footnote 12

b: Values adjusted to represent chemical species in current IMPROVE light extinction algorithm; Trijonis estimates were 0.1 µg/m^3 and 0.2 µg/m^3 of ammonium bisulfate.

c: Values adjusted to represent chemical species in current IMPROVE light extinction algorithm; Trijonis estimates were 0.5 µg/m^3 and 1.5 µg/m^3 of organic compounds.

The EPA guidance also makes provision for refined estimates of site-specific natural haze that differ from the default values using either data analysis or model simulations. However, most states have continued to use the default natural haze levels for calculating the progress toward natural visibility conditions.

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[16] Trijonis, J. C. Characterization of Natural Background Aerosol Concentrations. Appendix A in Acidic Deposition: State of Science and Technology. Report 24. Visibility: Existing and Historical Conditions -- Causes and Effects. J. C. Trijonis, lead author. National Acid Precipitation Assessment Program: Washington, DC, 1990.

[17] Tombach, I., (2008) *Natural Haze Levels Sensitivity -- Assessment of Refinements to Estimates of Natural Conditions,* Report to the Western Governors Association, January 2008, available at http://www.wrapair.org/forums/aamrf/projects/NCB/index.html.

[18] Pitchford, M., Malm, W., Schichtel, B., Kumar, N., Lowenthal, D., Hand, J., Revised Algorithm for Estimating Light Extinction from IMPROVE Particle Speciation Data, J. Air & Waste Manage, Assoc. 57: 1326 – 1336, 2007.

Tombach and Brewer[19] reviewed natural sources of PM and identified several Class I areas for which evidence supports adjustments to the natural levels. Tombach[8] also reviewed estimates of natural haze levels and proposed that, instead of using two sets of default natural PM concentrations for the eastern and western US, a large number of sensitivity zones should be developed that reflect regional variability in natural PM sources. Tombach[8] also suggested that modeling studies are a possible approach to further revise estimates of natural PM concentrations.

Previous modeling studies have shown that the estimates of natural visibility described above for “clean” days will differ from the results of model simulations when United States anthropogenic emissions are totally eliminated (Tonnesen et al., 2006[20]; Koo et al., 2010[21]), especially when natural wild fire emissions are included in the model simulation. Because the URP is calculated using model simulations of PM on the 20% of days with the worst visibility, wild fires and other extreme events can result in estimated levels of natural haze (even without any contribution of US anthropogenic sources) that can be significantly greater than the natural levels used in the EPA guidance for URP calculation. This could make it difficult or impossible for states to identify emissions control measures sufficient to demonstrate the URP toward attaining visibility goals because the endpoint is unachievable even if all US anthropogenic emissions are eliminated, as North Dakota has already determined even for the interim goal in 2018.

Previous Suppression of Wildfire Activity and its Effect upon the EPA Default Natural Conditions

Throughout history, except for the past few decades, fires have been used to clear land, change plant and tree species, sterilize land, maintain certain types of habitat, among other purposes. Native Americans used fires as a technique to maintain certain pieces of land or to improve habitats. Although early settlers often used fires in the same way as the Native Americans, major wildfires on public domain land were largely ignored and were often viewed as an opportunity to open forestland for grazing.

Especially large fires raged in North America during the 1800s and early 1900s. The public was becoming slowly aware of fire's potential for life-threatening danger. Federal involvement in trying to control forest fires began in the late 1890s with the hiring of General Land Office rangers during the fire season. When the management of the forest reserves (now called national forests) was transferred to the newly formed Forest Service in 1905, the agency took on the responsibility of creating professional standards for firefighting, including having more rangers and hiring local people to help put out fires.

Since the beginning of the 20th century, fire suppression has resulted in a buildup of vegetative “fuels” and catastrophic wildfires. Recent estimates of background visual range, such as Trijonis[16], have underestimated the role of managed fire on regional haze. Since about 1990, various government agencies have increased prescribed burning to reduce the threat of dangerous wildfires, and the

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[19] Tombach, I., and Brewer, P. (2005). Natural Background Visibility and Regional Haze Goals in the Southeastern United States. *J. Air & Waste Manage. Assoc. 55*, 1600-1620.

[20] Tonnesen, G., Omary, M., Wang, Z., Jung, C.J., Morris, R., Mansell, G., Jia, Y., Wang, B., and Z. Adelman (2006) Report for the Western Regional Air Partnership Regional Modeling Center, University of California Riverside, Riverside, California, November. (http://pah.cert.ucr.edu/aqm/308/reports/final/2006/WRAP-RMC_2006_report_FINAL.pdf).

[21] Koo B., C.J. Chien, G. Tonnesen, R. Morris , J. Johnson, T. Sakulyanontvittaya, P. Piyachaturawat, and G.Yarwood, 2010. Natural emissions for regional modeling of background ozone and particulate matter and impacts on emissions control strategies. Atm. Env., 44, 2372-2382.

increased haze due to these fires is often more of an impairment to visibility than industrial sources, especially for NO_X reductions that are only effective in winter, the time of the lowest tourist visitation in most cases.

The National Park Service indicates at http://www.nps.gov/thro/parkmgmt/firemanagement.htm for the Theodore Roosevelt National Park that:

"For most of the 20th Century, wildfires were extinguished immediately with the assumption that doing so would protect lives, property, and natural areas. However, following the unusually intense fire season of 1988, agencies including the National Park Service began to rethink their policies." Even this policy is not always successful, as experienced by the USDA Forest Service[22] in their management of wildfires near the Boundary Waters Canoe Area that can contribute significantly to visibility degradation during the peak tourist season. In this case, even small fires, if left unchecked, have been known to evolve into uncontrollable fires and then require substantial resources to extinguish.

EPA's 2003 "Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program" acknowledges that wildfires are a contributor to natural visibility conditions, but the data used in estimates of natural conditions were taken during a period of artificial fire suppression so that the true impact of natural wildfires is understated. The report notes that "data should be available for EPA and States to develop improved estimates of the contribution of fire emissions to natural visibility conditions in mandatory Federal Class I areas over time." As noted by several studies noted above, the impact due to natural fire levels is underestimated in the EPA natural visibility background estimates. The consequences of the artificially low estimates of natural visibility conditions include the distortion of Reasonable Progress analyses and also to BART modeling results that overestimate the visibility improvement achievable from NO_X emission reductions due to the use of inaccurate natural visibility conditions.

Recommendations for an Improved Estimate of Visibility Natural Conditions

A reasonable approach would be to combine the effects of the uncontrollable particulate matter components and the emissions from international sources to determine a new glide path endpoint that is achievable by controlling (only) U.S. anthropogenic emissions. To compute this new endpoint, regional photochemical modeling using CMAQ or CAMx could be conducted for the base case (already done) and then for a future endpoint case that has no U.S. anthropogenic emissions, but with natural particulate matter emissions (e.g., dust, fires, organic matter) as well as fine particulate, SO_2 and NO_x emissions associated with all non-U.S. sources set to the current baseline levels. The simulation should include an higher level of wildfire activity than in the recent past to reflect a truer level of fire activity before manmade suppression in the 20th century. Then, states could use a relative reduction factor (RRF) approach to determine the ratio of the haze impacts between the base case and the reasonable future case, and then apply the RRF values to the baseline haze to obtain a much more reasonable "natural conditions" haze endpoint. The more accurate natural background would also result in a reduction in the degree to which CALPUFF modeling overstates visibility improvement from emission reductions.

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[22] See explanation at http://www.msnbc.msn.com/id/48569985/ns/us_news-environment/t/forest-service-gets-more-aggressive-small-fires/.

APPENDIX B

MODEL OVERPREDICTION ISSUES FOR WINTERTIME NITRATE HAZE

This appendix includes a discussion of CALPUFF predictions for nitrate haze, followed by more general issues with CALPUFF predictions.

CALPUFF Predictions of Nitrate Haze

Secondary pollutants such as nitrates and sulfates contribute to light extinction in Class I areas. The CALPUFF model was approved by EPA for use in BART determinations to evaluate the effect of these pollutants on visibility in Class I areas. CALPUFF version 5.8 (the current guideline version) uses the EPA-approved MESOPUFF II chemical reaction mechanism to convert SO_2 and NO_X emissions to secondary sulfate and nitrate. This section describes how secondary pollutants, specifically nitrate, are formed and the factors affecting their formation, especially as formulated in CALPUFF.

In the CALPUFF model, the oxidation of NO_X to nitric acid (HNO_3) depends on the NO_X concentration, ambient ozone concentration, and atmospheric stability. Some of the nitric acid is then combined with available ammonia in the atmosphere to form ammonium nitrate aerosol in an equilibrium state that is a function of temperature, relative humidity, and ambient ammonia concentration. In CALPUFF, total nitrate ($TNO_3 = HNO_3 + NO_3$) is partitioned into gaseous HNO_3 and NO_3 particles according to the equilibrium relationship between the two species. This equilibrium is a function of ambient temperature and relative humidity. Moreover, the formation of nitrate particles *strongly* depends on availability of NH_3 to form ammonium nitrate, as shown in Figure 6[23]. The figure on the left shows that with 1 ppb of available ammonia and fixed temperature and humidity (for example, 275 K and 80% humidity), only 50% of the total nitrate is in the form of particulate matter. When the available ammonia is increased to 2 ppb, as shown in the figure on the right, as much as 80% of the total nitrate is in the particulate form. Figure B-1 also shows that colder temperatures and higher relative humidity favor particulate nitrate formation. A summary of the conditions affecting nitrate formation are listed below:

- Colder temperature and higher relative humidity create more favorable conditions to form nitrate particulate matter in the form of ammonium nitrate;
- Warmer temperatures and lower relative humidity create less favorable conditions for nitrate particulate matter resulting in a small fraction of total nitrate in the form of ammonium nitrate;
- Ammonium sulfate formation preferentially scavenges available atmospheric ammonia over ammonium nitrate formation. In air parcels where sulfate concentrations are high and ambient ammonia concentrations are low, there is less ammonia available to react with nitrate, and less ammonium nitrate is formed.

The effects of temperature and background ammonia concentrations on the nitrate formation are the key to understanding the effects of various NO_X control options. For the reasons discussed above, the seasons with lower temperatures are the most likely to be most important for ammonium nitrate formation when regional haze is more effectively reduced by controlling NO_X.

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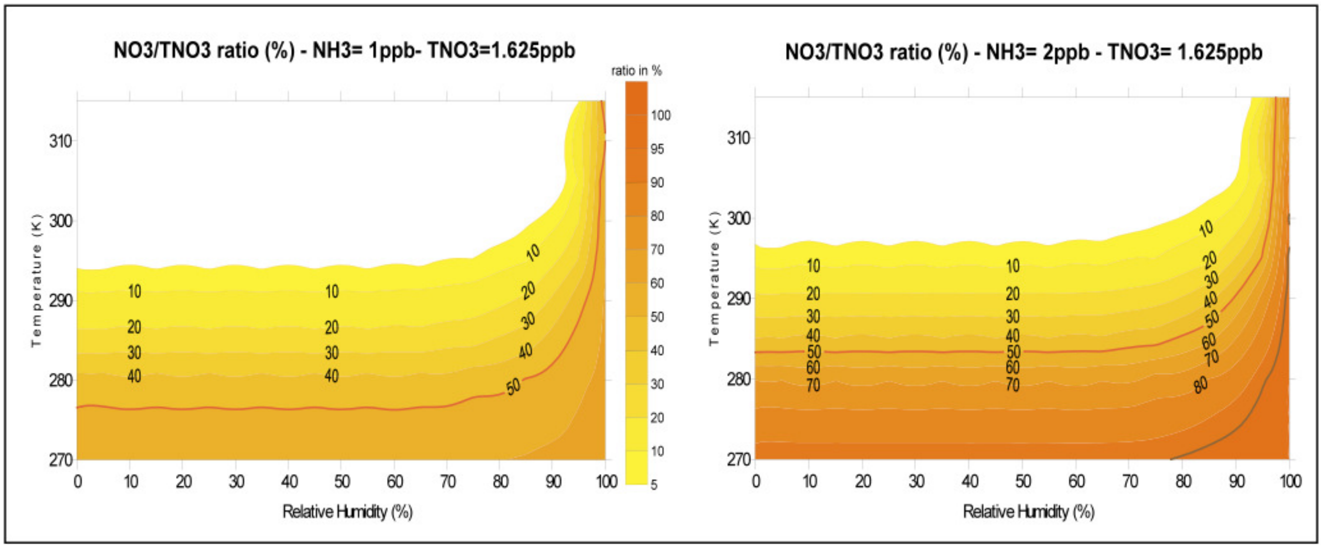
[23] Scire, Joseph. CALPUFF MODELING SYSTEM. CALPUFF course presented at Chulalongkorn University, Bangkok, Thailand. May 16-20, 2005; slide 40 available at http://aqnis.pcd.go.th/tapce/plan/4CALPUFF%20slides.pdf, accessed March 2011.

Figure B-1: NO_3/HNO_3 Equilibrium Dependency on Temperature and Humidity



Sensitivity of CALPUFF Haze Calculations to Background Ammonia Concentration

In an independent analysis, the Colorado Department of Public Health and Environment (CDPHE) performed a sensitivity modeling analysis to explore the effect of the specified ammonia concentration applied in CALPUFF on the predicted visibility impacts for a source with high NO_X emissions relative to SO_2 emissions[24]. The results of the sensitivity modeling are shown in Figure B-2. It is noteworthy that the largest sensitivity occurs for specified ammonia input between 1 and 0.1 ppb. In that factor-of-ten range, the difference in the peak visibility impact predicted by CALPUFF is slightly more than a factor of three. This sensitivity analysis shows that the specification of background ammonia is very important in terms of the magnitude of visibility impacts predicted by CALPUFF. The fact that regional, diurnal and seasonal variations of ambient ammonia concentrations are not well-characterized and mechanisms not well-understood effectively limits the effectiveness of CALPUFF in modeling regional haze, especially in terms of the contribution of ammonium nitrate.

It is also noteworthy that CALPUFF version 5.8's demonstrated over-predictions of wintertime nitrate can be mitigated to some extent by using lower winter ammonia background values, although there is not extensive measurement data to determine the ambient ammonia concentrations. This outcome showing the superiority of the monthly-varying background ammonia concentrations was found by Salt River

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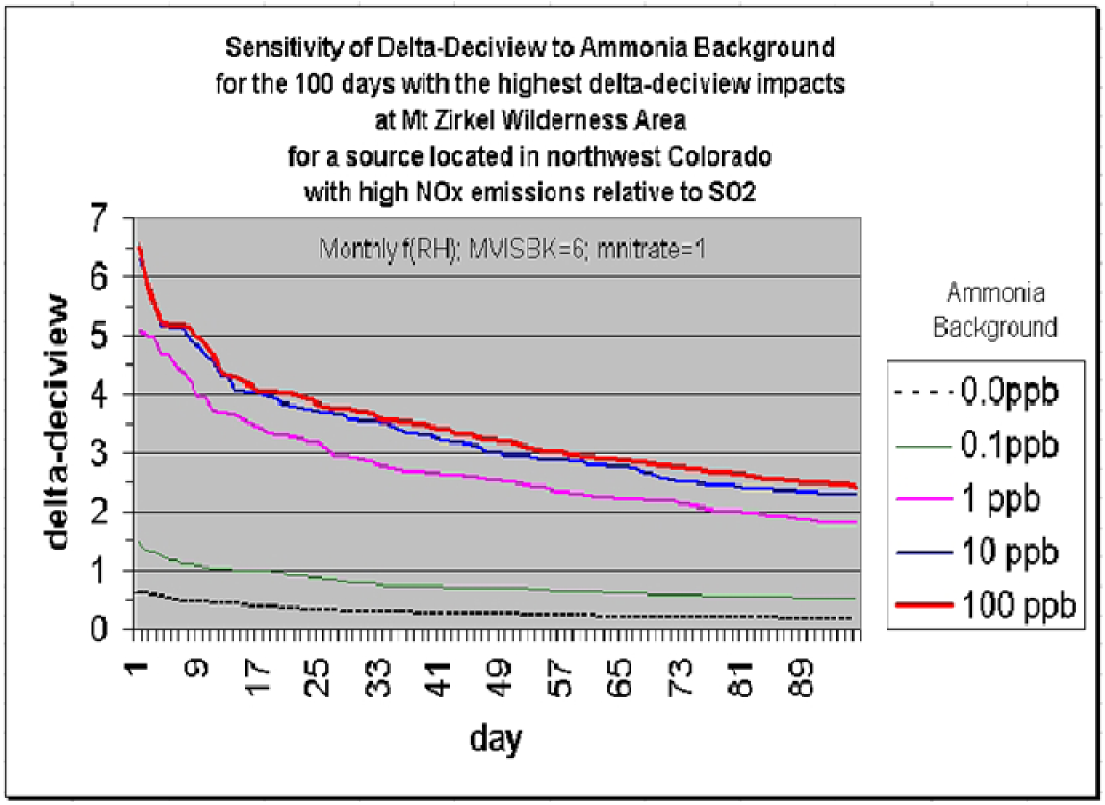
[24] Supplemental BART Analysis: CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis (DRAFT), revised June 25, 2010, available at http://www.colorado.gov/airquality/documents/Draft-ColoradoSupplementalBARTAnalysisCALPUFFProtocol-25June2010.pdf. (2010)

Project in case studies of the Navajo Generating Station impacts on Grand Canyon monitors, as presented[25] to EPA in 2010.

It is important to note that 14 years ago in 1998, when the IWAQM Phase 2 guidance[26] was issued, CALPUFF did not even have the capability of accommodating monthly ammonia background concentrations; only a single value was allowed. Since then, CALPUFF has evolved to be able to receive as input monthly varying ammonia concentrations. EPA's guidance on the recommended input values that are constant all year has not kept pace with the CALPUFF's capability. The weight of evidence clearly indicates that the use of monthly varying ammonia concentrations with lower wintertime values will result in more accurate predictions.

Figure B-2: CDPHE Plot of Sensitivity of Visibility Impacts Modeled by CALPUFF for Different Ammonia Backgrounds.



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[25] Salt River Project, 2010. Measurements of Ambient Background Ammonia on the Colorado Plateau and Visibility Modeling Implications. Salt River Project, P.O. Box 52025 PAB352, Phoenix, Arizona 85072.

[26] IWAQM Phase 2 Summary Report and Recommendations (EPA-454/R-98-019), EPA OAQPS, December 1998). http://www.epa.gov/scram001/7thconf/calpuff/phase2.pdf.

Independent Studies of the Effect of Model Chemistry on Nitrate Predictions

The Regional Haze BART Rule acknowledged that CALPUFF tends to overestimate the amount of nitrate that is produced. In particular, the overestimate of ammonium nitrate concentrations on visibility at Class I areas is the greatest in the winter, when temperatures (and visitation) are lowest, the nitrate concentrations are the greatest, and the sulfate concentrations tend to be the least due to reduced oxidation rates of SO_2 to sulfate.

On page 39121, the BART rule[27] stated that: "…the simplified chemistry in the [CALPUFF] model tends to magnify the actual visibility effects of that source."

On page 39123, the BART rule stated that: "We understand the concerns of commenters that the chemistry modules of the CALPUFF model are less advanced than some of the more recent atmospheric chemistry simulations. In its next review of the Guideline on Air Quality Models, EPA will evaluate these and other newer approaches[28]."

EPA did not conduct such an evaluation, but the discussion below reports on the efforts of other investigators.

A review of independent evaluations of the CALPUFF model is reported here, with a focus on identifying studies that address the nitrate chemistry used in the model. Morris et al.[29] reported that the CALPUFF MESOPUFF II transformation rates were developed using temperatures of 86, 68 and 50°F. Therefore, the 50°F minimum temperature used in development of the model could result in overestimating sulfate and nitrate formation in colder conditions. These investigators found that CALPUFF tended to overpredict nitrate concentrations during winter by a factor of about three.

A recent independent study of the CALPUFF performance by Karamchandani et al (referred to here as the KCBB study) is highly relevant to this issue[30]. The KCBB study presented several improvements to the Regional Impacts on Visibility and Acid Deposition (RIVAD) chemistry option in CALPUFF, an alternative treatment that was more amenable to an upgrade than the MESOPUFF II chemistry option. Among other items, the improvements included the replacement of the original CALPUFF secondary particulate matter (PM) modules by newer algorithms that are used in current state-of-the-art regional air quality models such as CMAQ, CMAQ-MADRID, CAMx and REMSAD, and in advanced puff models

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[27] July 6, 2005 Federal Register publication of the Regional Haze BART rule.

[28] The next (9th) EPA modeling conference was held in 2008, during which the concepts underlying the chemistry upgrades in CALPUFF 6.42 were presented. However, EPA failed to conduct the promised evaluation in its review of techniques at that conference held 4 years ago. As a result of the 10th EPA modeling conference held in March 2012, EPA appears to be continuing to rely upon CALPUFF version 5.8, which it admitted in the July 6, 2005 BART rule has serious shortcomings.

[29] Morris, R., Steven Lau and Bonyoung Koo. Evaluation of the CALPUFF Chemistry Algorithms. Presented at A&WMA 98th Annual Conference and Exhibition, June 21-25, 2005 Minneapolis, Minnesota. (2005)

[30] Karamchandani, P., S. Chen, R. Bronson, and D. Blewitt. Development of an Improved Chemistry Version of CALPUFF and Evaluation Using the 1995 SWWYTAF Data Base. Presented at the Air & Waste Management Association Specialty Conference on Guideline on Air Quality Models: Next Generation of Models, October 28-30, 2009, Raleigh, NC. (2009)

such as SCICHEM. In addition, the improvements included the incorporation of an aqueous-phase chemistry module based on the treatment in CMAQ. Excerpts from the study papers describing each of the improvements made to CALPUFF in the KCBB study are repeated below.

Gas-Phase Chemistry Improvements

The KCBB study applied a correction to CALPUFF in that the upgraded model was modified to keep track of the puff ozone concentrations between time steps. The authors also updated the oxidation rates of SO_2 and nitrogen dioxide (NO_2) by the hydroxide ion (OH^-) to the rates employed in contemporary photochemical and regional PM models.

Treatment of Inorganic Particulate Matter

The KCBB study scientists noted that the EPA-approved version of CALPUFF currently uses a simple approach to simulate the partitioning of nitrate and sulfate between the gas and particulate phases. In this approach, sulfate is appropriately assumed to be entirely present in the particulate phase, while nitrate is assumed to be formed by the reaction between nitric acid and ammonia.

The KCBB study implemented an additional treatment for inorganic gas-particle equilibrium, based upon an advanced aerosol thermodynamic model referred to as the ISORROPIA model[31]. This model is currently used in several state-of-the-art regional air quality models. With this new module, the improved CALPUFF model developed in the KCBB study includes a treatment of inorganic PM formation that is consistent with the state of the science in air quality modeling, and is critical for the prediction of regional haze due to secondary nitrate formation from NO_X emissions.

Treatment of Organic Particulate Matter

The KCBB study added a treatment for secondary organic aerosols (SOA) that is coupled with the corrected RIVAD scheme described above. The treatment is based on the Model of Aerosol Dynamics, Reaction, Ionization and Dissolution (MADRID)[32,33], which treats SOA formation from both anthropogenic and biogenic volatile organic compound emissions.

Aqueous-Phase Chemistry

The current aqueous-phase formation of sulfate in both CALPUFF's RIVAD and MESOPUFF II schemes is currently approximated with a simplistic treatment that uses an arbitrary pseudo-first order rate in the presence of clouds (0.2% per hour), which is added to the gas-phase rate. There is no explicit treatment

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[31] Nenes A., Pilinis C., and Pandis S.N. Continued Development and Testing of a New Thermodynamic Aerosol Module for Urban and Regional Air Quality Models, *Atmos. Env.* **1998**, 33, 1553-1560.

[32] Zhang, Y., B. Pun, K. Vijayaraghavan, S.-Y. Wu, C. Seigneur, S. Pandis, M. Jacobson, A. Nenes and J.H. Seinfeld. Development and Application of the Model of Aerosol Dynamics, Reaction, Ionization and Dissolution (MADRID), *J. Geophys. Res.* **2004**, 109, D01202, doi:10.1029/2003JD003501.

[33] Pun, B., C. Seigneur, J. Pankow, R. Griffin, and E. Knipping. An upgraded absorptive secondary organic aerosol partitioning module for three-dimensional air quality applications, 24th Annual American Association for Aerosol Research Conference, Austin, TX, October 17-21, 2005. (2005)

of aqueous-phase SO_2 oxidation chemistry. The KCBB study incorporated into CALPUFF a treatment of sulfate formation in clouds that is based on the treatment that is used in EPA's CMAQ model.

CALPUFF Model Evaluation and Sensitivity Tests

The EPA-approved version of CALPUFF and the version with the improved chemistry options were evaluated using the 1995 Southwest Wyoming Technical Air Forum (SWWYTAF) database[34], available from the Wyoming Department of Environmental Quality. The database includes MM5 output for 1995, CALMET and CALPUFF codes and control files, emissions for the Southwest Wyoming Regional modeling domain, and selected outputs from the CALPUFF simulations. Several sensitivity studies were also conducted to investigate the effect of background NH_3 concentrations on model predictions of PM nitrate. Twice-weekly background NH_3 concentrations were provided from monitoring station observations for the Pinedale, Wyoming area. These data were processed to calculate seasonally averaged background NH_3 concentrations for CALPUFF.

Two versions of CALPUFF with different chemistry modules were evaluated with this database:

1. MESOPUFF II chemistry using the Federal Land Managers' Air Quality Related Values Work Group (FLAG) recommended background NH_3 concentration of 1 ppb for arid land. As discussed previously, the MESOPUFF II algorithm is the basis for the currently approved version of CALPUFF that is being used for BART determinations throughout the United States.

2. Improved CALPUFF RIVAD/ARM3 chemistry using background values of NH_3 concentrations based on measurements in the Pinedale, Wyoming area, as described above.

PM sulfate and nitrate were predicted by the two models and compared with actual measured values obtained at the Bridger Wilderness Area site from the IMPROVE network and the Pinedale site from the Clean Air Status and Trends Network (CASTNET). For the two model configurations evaluated in this study, the results for PM sulfate were very similar, which was expected since the improvements to the CALPUFF chemistry were anticipated to have the most impact on PM nitrate predictions. Therefore, the remaining discussion focuses on the performance of each model with respect to PM nitrate.

The EPA-approved CALPUFF model was found to significantly overpredict PM nitrate concentrations at the two monitoring locations, by a factor of two to three. The performance of the version of CALPUFF with the improved RIVAD chemistry was much better, with an overprediction of about 4% at the Pinedale CASTNET site and of about 28% at the Bridger IMPROVE site.

In an important sensitivity analysis conducted within the KCBB study, both the EPA-approved version of CALPUFF and the improved version were run with a constant ammonia background of 1 ppb, as recommended by IWAQM Phase II[35]. The results were similar to those noted above: the improved

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[34] Wyoming Department of Environmental Quality. 1995 Southwest Wyoming Technical Air Forum (SWWYTAF) database. Background and database description are available at http://deq.state.wy.us/aqd/prop/2003AppF.pdf. (2010)

[35] Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Long-Range Transport Modeling, EPA-454/R-98-019. (1998)

CALPUFF predictions were about two to three times lower than those from the EPA-approved version of CALPUFF. This result is similar to the results using the seasonal observed values of ammonia, and indicates that the sensitivity of the improved CALPUFF model to the ammonia input value is potentially less than that of the current EPA-approved model.

Similar sensitivity was noted by Scire et al. in their original work in the SWWYATF study[36], in which they tested seasonally varying levels of background ammonia in CALPUFF (using 0.23 ppb in winter, for example; see Figure B-3. The sensitivity modeling for predicting levels of nitrate formation shows very similar results to those reported in the KCBB study.

These findings indicate that to compensate for the tendency of the current EPA-approved version of CALPUFF to overpredict nitrates, the background ammonia values that should be used as input in CALPUFF modeling should be representative of isolated areas (e.g., Class I areas).

On November 3, 2010, TRC released a new version (6.42) of CALPUFF to fix certain coding "bugs" in EPA-approved version 5.8 and to improve the chemistry module. Additional enhancements to CALPUFF version 6.42 have been reported at EPA's 10th modeling conference in March 2012 by Scire[37], who also has conducted recent evaluations of this version in comparison to the regulatory version (5.8). Despite the evidence that this CALPUFF version is a generation ahead of the currently approved version for modeling secondary particulate formation, EPA has not acted to adopt it as a guideline model. Even with evidence provided by independent investigators[29,30] that also indicate that wintertime nitrate estimated by CALPUFF version 5.8 is generally overpredicted by a factor between 2 and 4, EPA has not taken steps to adopt the improved CALPUFF model, noting that extensive peer review, evaluations, and rulemaking are still needed for this adoption to occur. In the meantime, EPA, in retaining CALPUFF version 5.8 as the regulatory model for regional haze predictions, is ignoring the gross degree of overestimation of particulate nitrate and is thus ensuring that regional haze modeling conducted for BART is overly conservative. EPA's delay in adopting CALPUFF version 6.42 will thus result in falsely attributing regional haze mitigation to NO_X emission reductions.

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[36] Scire, J.S., Z-X Wu, D.G. Strimaitis and G.E. Moore. The Southwest Wyoming Regional CALPUFF Air Quality Modeling Study – Volume I. Prepared for the Wyoming Dept of Environmental Quality. (2001)

[37] Scire, J., 2012. New Developments and Evaluations of the CALPUFF Model. http://www.epa.gov/ttn/scram/10thmodconf/presentations/3-5-CALPUFF_Improvements_Final.pdf.

OVERPREDICTIONS OF NITRATE HAZE BY REGIONAL PHOTOCHEMICAL MODELS

The overprediction tendency for modeling of wintertime nitrate haze is not limited to CALPUFF. Even the state-of-the-art regional photochemical models are challenged in getting the right ammonium nitrate concentrations. This is evident in a presentation[38] made by Environ to the CENRAP Regional Planning Organization in 2006. The relevant figures from the Ralph Morris presentation (shown in Figures B-4 and B-5 below) indicate that both CMAQ and CAMx significantly overpredict nitrate haze in winter at Voyageurs National Park, by about a factor of 2. This is shown by the height of the red portion of the composition plot stacked bars between the observed and predicted timelines. It is noteworthy that Minnesota and EPA have relied upon this modeling approach for their BART determinations. Similar to CALPUFF, as discussed above, the agency modeling is prone to significantly overpredicting wintertime nitrate haze, leading to an overestimate of visibility improvement with NO_X emission reductions.

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[38] http://pah.cert.ucr.edu/aqm/cenrap/meetings.shtml, under “MPE”, slides 9 and 10.

Figure B-3: Sensitivity Study of Nitrate Predictions at Bridger Wilderness Area for Input Ammonia Concentrations to CALPUFF (0.23, 0.5, and 1.0 ppb).

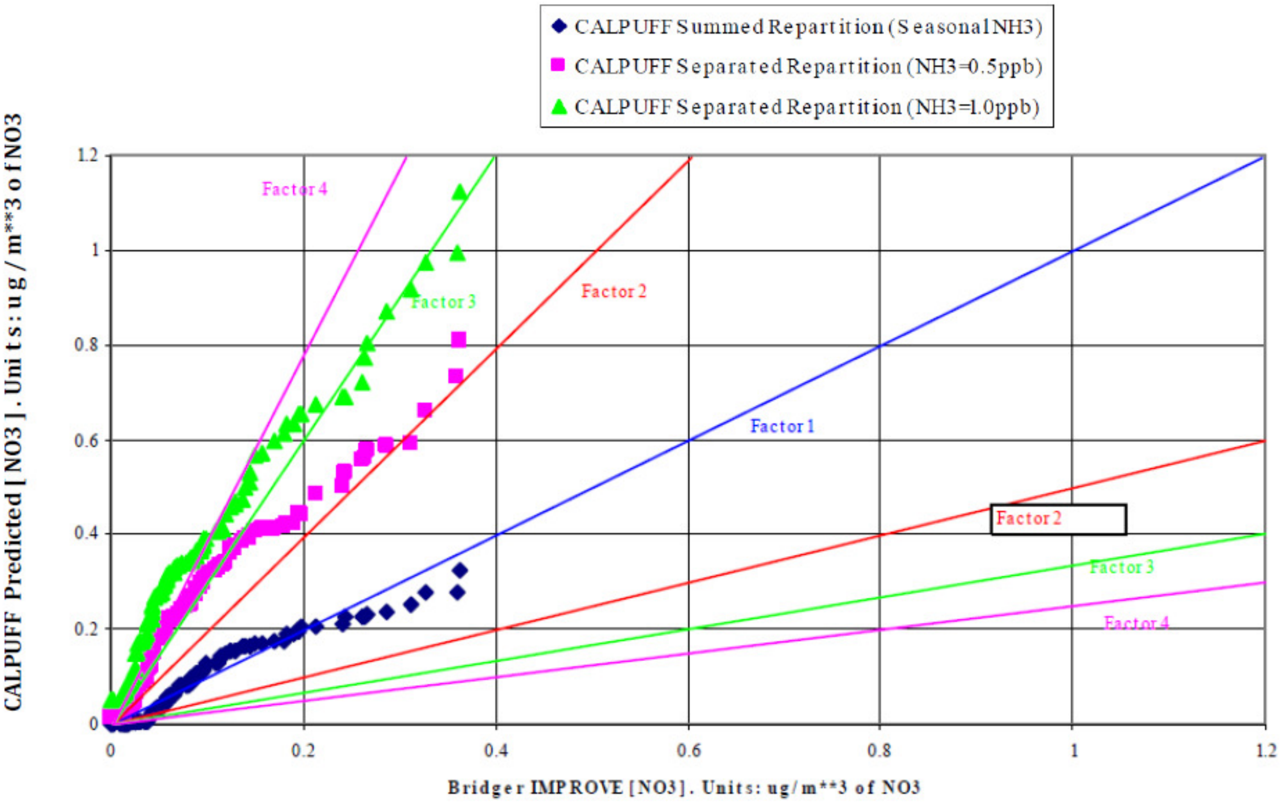


Figure B-4 CMAQ vs. Observed Haze Predictions at Voyageurs National Park

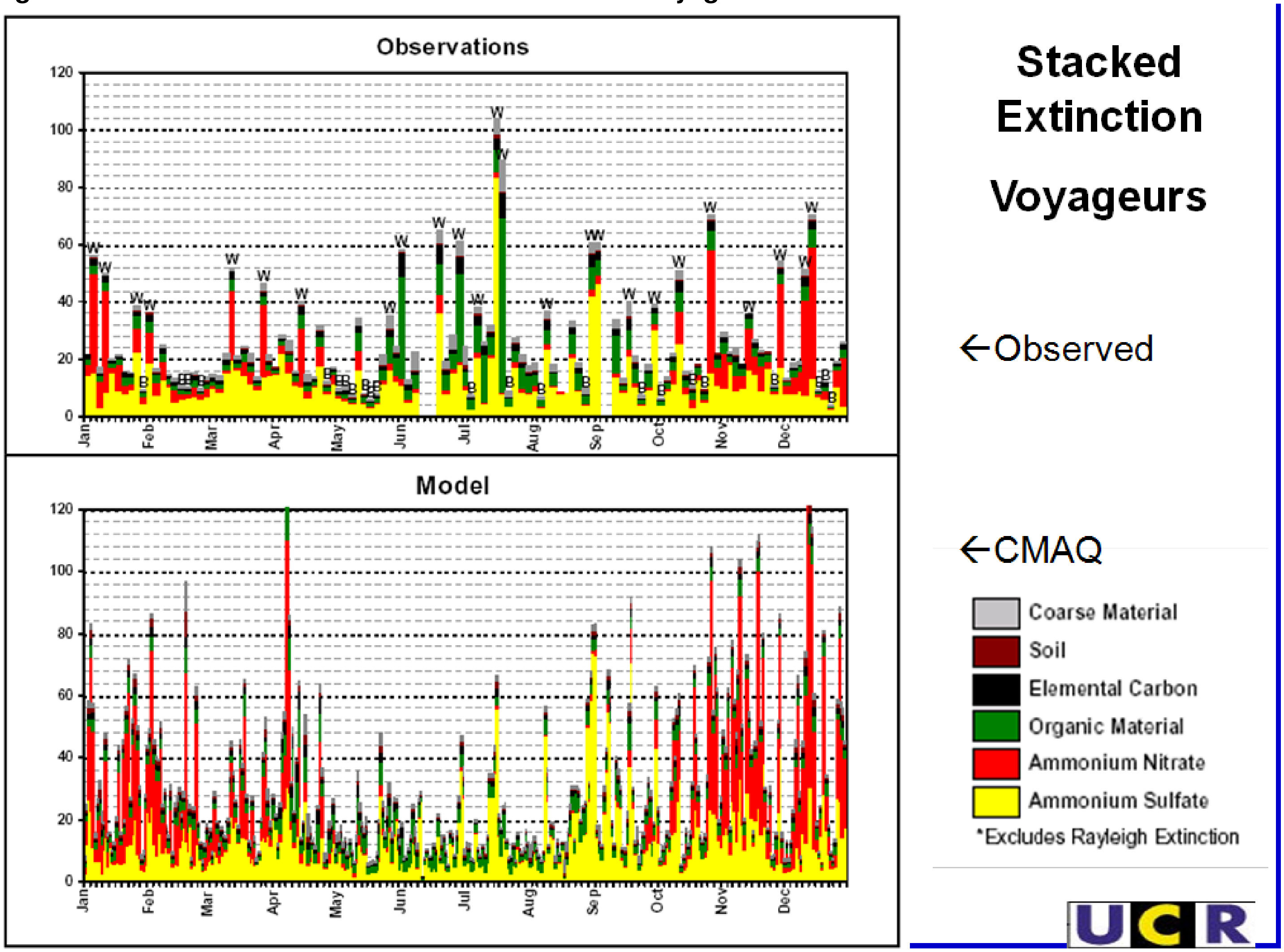
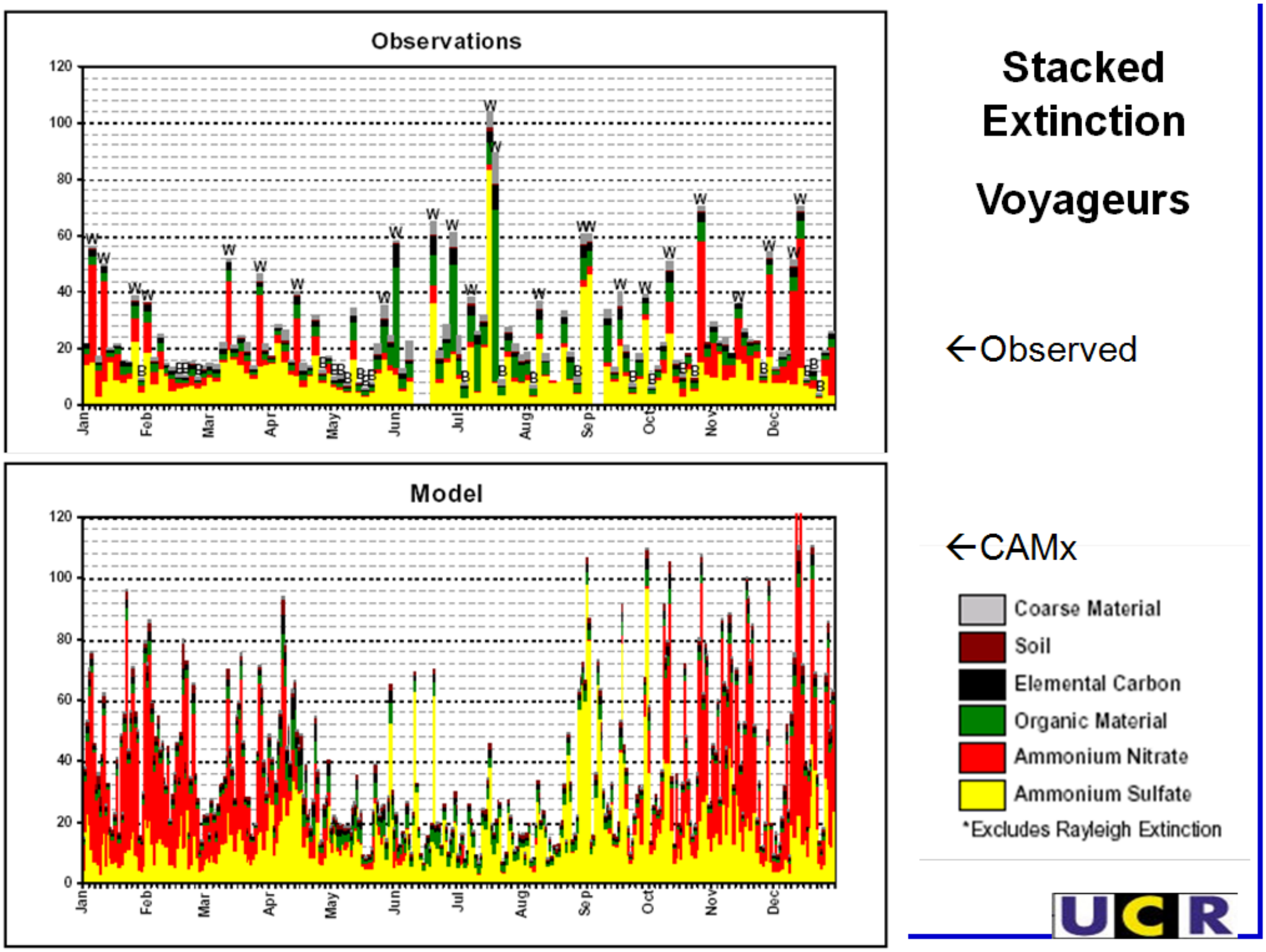


Figure B-5 CAMx vs. Observed Haze Predictions at Voyageurs National Park



APPENDIX C

Haze Time Series Plots for Voyageurs National Park, Seney Wilderness Area, and Isle Royale National Park

Figure C-1 Time Series of Nitrate Haze at Voyageurs National Park (2002-2010)

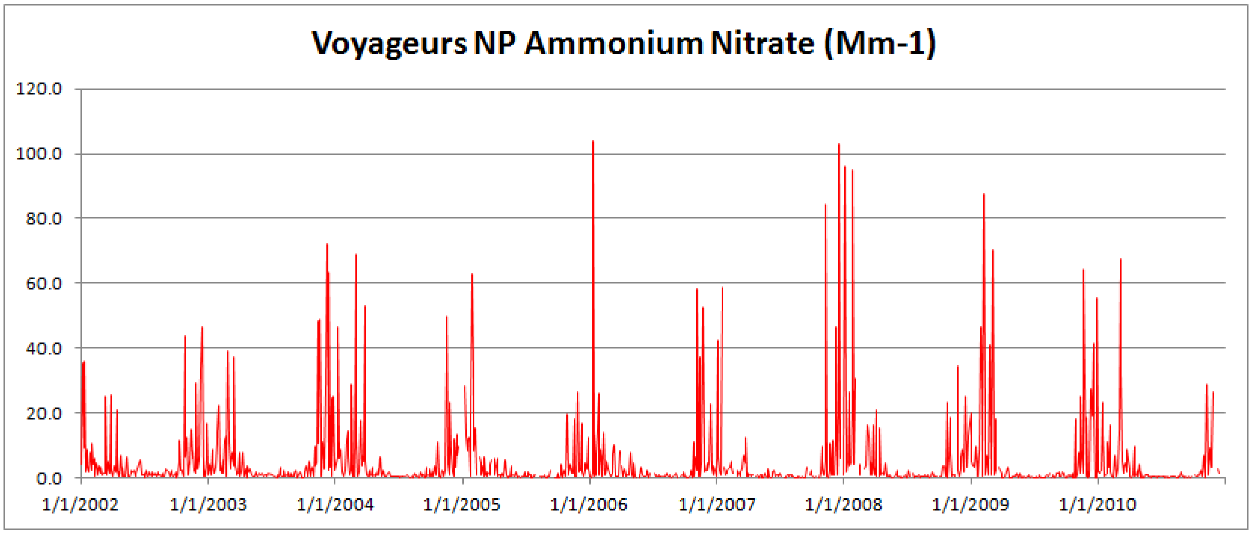


Figure C-2 Time Series of Sulfate Haze at Voyageurs National Park (2002-2010)

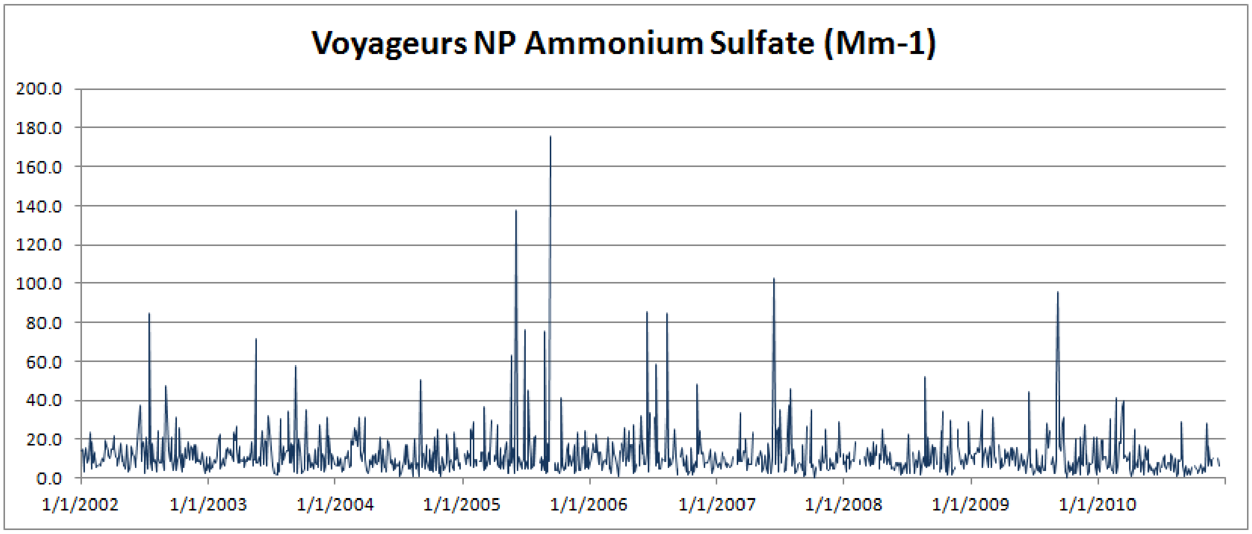


Figure C-3 Time Series of Nitrate Haze at Seney Wilderness Area (2002-2010)

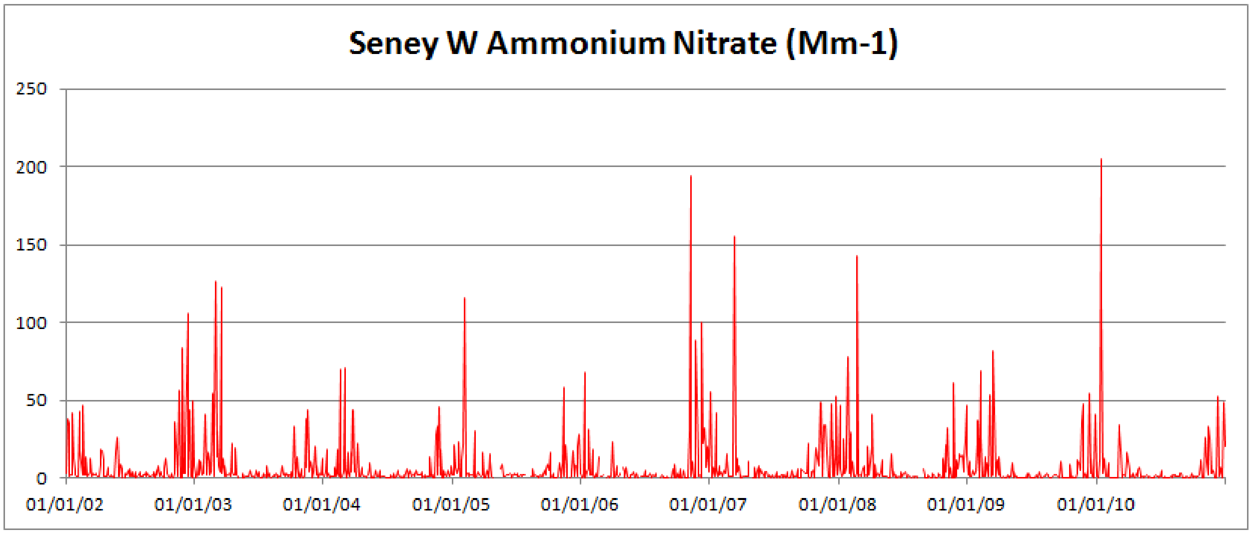


Figure C-4 Time Series of Sulfate Haze at Seney Wilderness Area (2002-2010)

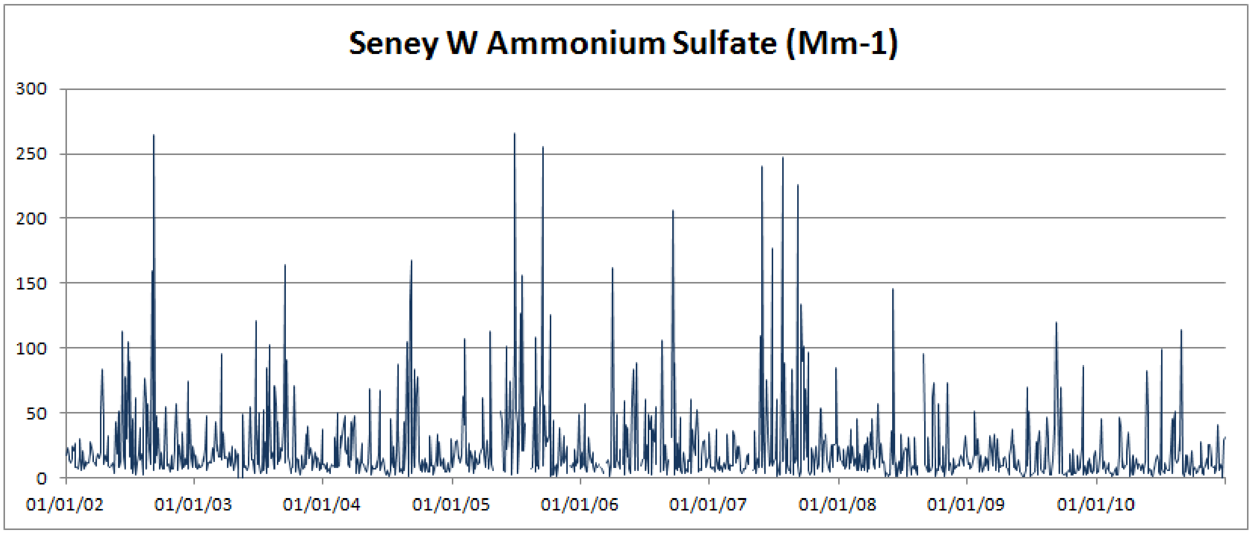


Figure C-5 Time Series of Nitrate Haze at Isle Royale National Park (2002-2010)

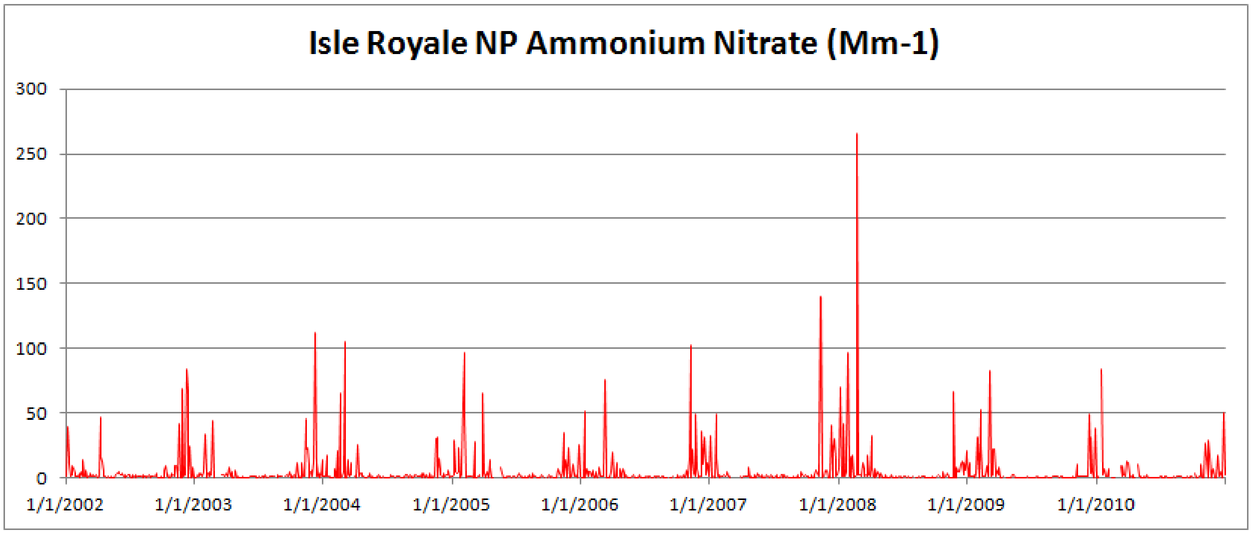
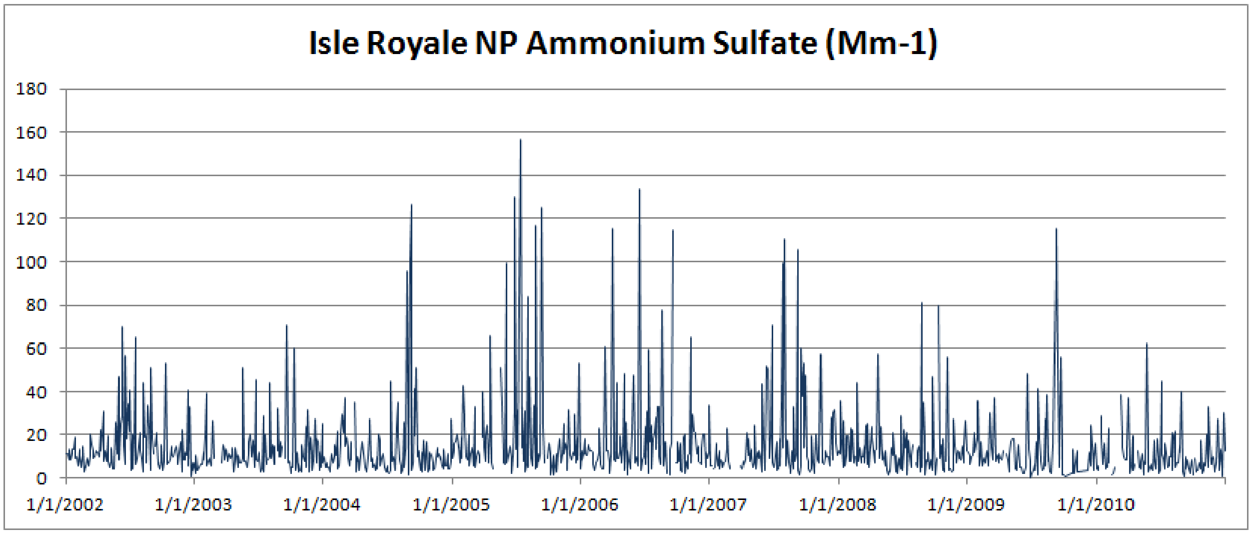


Figure C-6 Time Series of Sulfate Haze at Isle Royale National Park (2002-2010)



APPENDIX D

EXAMPLE OF VISIBILITY CHANGES AFTER ACTUAL EMISSION REDUCTIONS: SHUTDOWN OF THE MOHAVE GENERATING STATION

The Mohave Generating Station (MGS) shut down at the end of 2005, which should have had a large, beneficial effect (over 2 dv, according to CALPUFF) upon Grand Canyon visibility on the 98th percentile worst days. The MGS was a large (1590 MW) coal-fired plant located near the southern tip of Nevada (Laughlin, NV). MGS was placed in operation in the early 1970s, and was retired at the end of 2005 as a result of a consent agreement with the United States Environmental Protection Agency (EPA). The agreement had provided MGS with the option of continued operation if state-of-the-art emissions controls were installed for SO_2 and NOx emissions, but the owners determined that the cost of controls was too high to justify the investment. As a result, the plant was shut down on December 31, 2005 and has not been in operation since then.

As shown in Figure C-1, the MGS location is about 115 km away from the closest point of the Grand Canyon National Park, for which a southwesterly wind is needed to carry the emissions from MGS to most of the park. A multi-year study[39] completed by the EPA in 1999 (Project MOHAVE) indicated that MGS could be a significant contributor to haze in the Grand Canyon. In fact, typical annual emissions from MGS during the last several years of operation were approximately 40,000 tons per year (TPY) of SO_2 and 20,000 TPY of NOx. EPA noted in their Project MOHAVE conclusions that due to this level of emissions of haze precursors and its proximity to the Grand Canyon, MGS was the single largest emission source that could cause regional haze within the Grand Canyon.

Haze observations at three locations in the Grand Canyon (Meadview, Indian Garden, and Hance Camp monitors are available every third day for periods both before and after the plant shut down at the end of 2005. By comparing haze measurements before and after plant shutdown, it may be possible to determine whether the haze in the Grand Canyon has perceptibly changed since 2005 by reviewing the data from these three monitors. The Meadview monitor is at the western edge of the Park, and is relatively close to MGS. The other two IMPROVE monitors are located near some of the most heavily visited areas of the park (Hance Camp, on the South Rim, and Indian Garden, about 1,100 feet lower near the bottom of the canyon).

A 2010 *Atmospheric Environment* paper by Terhorst and Berkman[40] studied the effects of the opportunistic "experiment" afforded by the abrupt shutdown of the largest source affecting the Grand Canyon (according to EPA). The paper noted that Project MOHAVE's conclusions about the effects of MGS on the Grand Canyon visibility were ambiguous. The project's tracer studies revealed that while the MGS emissions did reach the park, particularly in the summer, there was no evidence linking these elevated concentrations with actual visibility impairment; indeed, "correlation between measured tracer concentration and both particulate sulfur and light extinction were virtually nil."

On the other hand, dispersion models produced results inconsistent with the observations. Noting the disconnect between the measurements and model predictions, EPA noted the disparity between the measurements and modeling results, but still appeared to favor the models when it concluded that MGS was the largest sole contributor to visibility impairment in the Grand Canyon.

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[39] Pitchford, M., Green, M., Kuhns, H., Scruggs, M., Tombach, I., Malm, W., Farber, R., Mirabella, V., 1999. Project MOHAVE: Final Report. Tech. Rep., U.S. Environmental Protection Agency (EPA).

[40] Jonathan Terhorst and Mark Berkman. "Effect of Coal-Fired Power Generation on Visibility in a Nearby National Park," Atmospheric Environment, 44(2010) 2544-2531. This publication is available by request from Mark Berkman at mark.berkman@berkeleyeconomics.com.

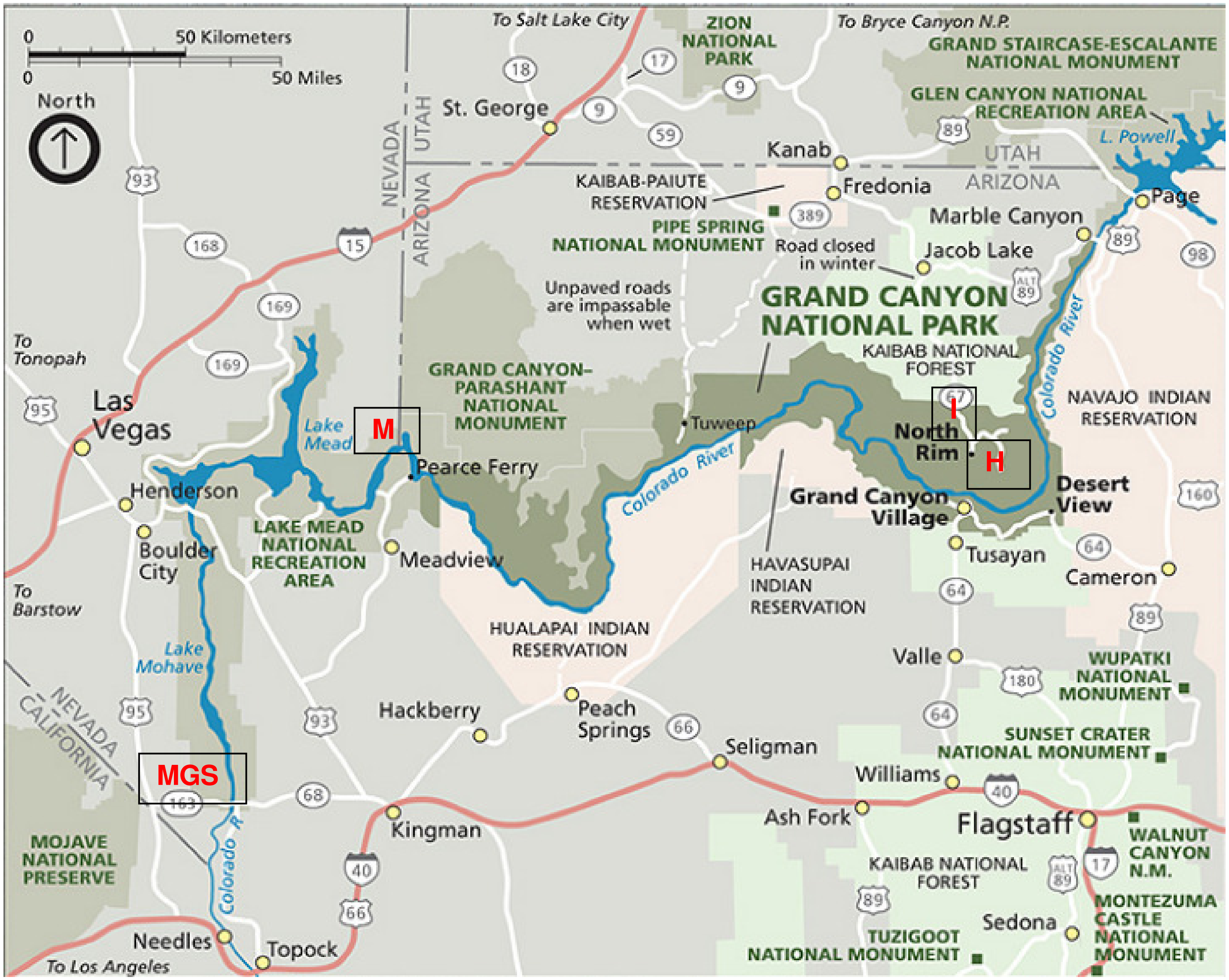
According to the authors, the Project Mohave observations were consistent with observations during temporary outages of MGS, for which there were no reports of substantial changes to visibility in the Grand Canyon.

Best Available Retrofit Technology (BART) studies evaluated a possible conversion of MGS to natural gas firing in 2008. These studies used the CALPUFF dispersion model in a manner prescribed by EPA to determine the change in visibility between the baseline emissions associated with coal firing to the natural gas firing alternative. The BART analyses conducted by the Nevada Department of Environmental Protection indicated that large differences in haze would result: an improvement of about 2.4 deciviews for the 98th percentile peak day, and a haze reduction to below 0.5 deciview on 186 days over 3 years modeled. Since natural gas firing would eliminate nearly all of the SO_2 emissions (although not all of the NOx emissions) this modeled result would tend to underestimate the visibility improvement that would be anticipated with a total plant shutdown.

Terhorst and Berkman analyzed several statistics to determine the change in sulfate concentrations and visibility in the Grand Canyon between the period 2003-2005 (pre-shutdown) and the period 2006-2008 (post-shutdown). They also considered other areas to determine how other regional and environmental effects might be reflected in changes at the Grand Canyon. Terhorst and Berkman calculated the average visibility over all IMPROVE monitoring days between 2003-2005 and 2006-2008, and determined that the average visibility was unchanged at Meadview, slightly improved on the South Rim (Hance Camp), and slightly worse at Indian Garden. Consistent with the observations of minimal visibility impact of MGS during Project MOHAVE, they concluded that the closure of MGS had a relatively minor effect on visibility in the Grand Canyon. These authors questioned the veracity of CALPUFF modeling (e.g., for BART) in that it predicts relatively large improvements in the Grand Canyon visibility that are not borne out by observations.

Emissions reductions associated with the shutdown of the Mohave Generating Station at the end of 2005 have provided an opportunistic means to discern the effect of retrofitting emission controls on coal-fired power plants in the western United States. In the case of MGS, although EPA had determined that this facility was the single most important contributor to haze in the Grand Canyon National Park and CALPUFF modeling using EPA's BART procedures provided predictions of significant improvements in haze, actual particulate and haze measurements taken before and after the shutdown do not reflect the large reductions that would be anticipated from these studies. This may be due in part to the fact that there are several aspects to the CALPUFF modeling procedures that greatly inflate the predicted haze (as noted below), and therefore, the predicted improvements due to emission reductions.

Figure D-1 : Map Showing the Relationship of the Mohave Generating Station to the Grand Canyon National Park



http://www.nps.gov/grca/planyourvisit/upload/GRCAmap2.pdf

H: Hance Camp monitor

I: Indian Garden monitor

M: Meadview monitor

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January 29, 2020

Jeff Minter, Environmental Health and Safety Administrator
Virginia Department of Public Utilities
618 2nd Street S
Virginia, MN 55792

RE: Request for Information - Regional Haze Rule, Reasonable Progress, Four Factor Analysis

Dear Mr. Minter:

The Minnesota Pollution Control Agency (MPCA) is currently preparing information for the second planning period (Round 2) comprehensive update to Minnesota's Regional Haze State Implementation Plan (SIP) as required by the Regional Haze Rule (40 CFR § 51.308). States are responsible for developing a Regional Haze SIP that addresses regional haze in each Class I area located within the state and in each Class I area located outside the state which may be affected by emissions from sources within the state. The Regional Haze SIP is required to identify existing facilities that cause or contribute to visibility impairment; analyze, identify, and apply federally-enforceable control strategies for those sources; and periodically demonstrate reasonable progress toward reaching visibility goals. States are also responsible for periodic comprehensive updates to their Regional Haze SIP that address these same topics. Minnesota's Round 2 Regional Haze SIP must be submitted to the U.S. Environmental Protection Agency (U.S. EPA) by July 31, 2021.

Minnesota has two Class I areas within its borders, the Boundary Waters Canoe Area Wilderness (BWCA) and Voyageurs National Park (Voyageurs). Other nearby Class I areas include Isle Royale National Park in Michigan. Therefore, Minnesota must prepare a Regional Haze SIP that identifies sources that cause or contribute to visibility impairment in these areas. To meet the core requirements for regional haze for these areas, Minnesota must submit a SIP that contains the plan elements and supporting documentation for all required analyses identified in 40 CFR § 51.308(f).

In the first planning period (Round 1), the focus of the Regional Haze Rule was on establishing Best Available Retrofit Technology (BART) for certain older sources and reasonable progress towards national visibility goals. In Round 2, there are no BART requirements; therefore, the focus is on making reasonable progress. The U.S. Environmental Protection agency has defined the methodology that states must use to determine what measures are necessary to make reasonable progress in 40 CFR § 51.308(f)(2). At minimum, the reasonable progress analysis must use the four factors identified in 40 CFR § 51.308(f)(2)(i) to evaluate and determine the emission reduction measures necessary to make reasonable progress. The four factors are:

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

Data from the IMPROVE monitoring sites at BWCA and Voyageurs indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X).

You are receiving this letter because your facility was identified as a significant source of NO_X and SO_2 and is located close enough to the BWCA or Voyageurs to potentially cause or contribute to visibility impairment in these Class I areas. Therefore, the MPCA requests that you prepare a “Four Factor Analysis” for the following emission units:

1. Boiler #9 (EQUI 3 / EU 003) that addresses emissions of NO_X and SO_2
2. Boiler #11 (EQUI 16 / EU 006) that addresses emissions of NO_X and SO_2

The analysis should be prepared using the U.S. Environmental Protection Agency guidance[1] that provides recommendations for how each of the factors should be determined.

Preparation of the comprehensive update to Minnesota’s Regional Haze SIP will require extensive planning and review of sources in Minnesota. The MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to prepare the Regional Haze SIP. The MPCA expects air quality modeling of potential regional emissions reductions will be conducted beginning in spring 2020. I appreciate your attention to this matter and request that you **submit the Four Factor Analysis by July 31, 2020**.

If you have any questions regarding this matter, or would like to request a meeting to further discuss the contents of this letter, please contact me by phone at 651-757-2653 or by email at Hassan.Bouchareb@state.mn.us.

Sincerely,

Hassan Bouchareb

This document has been electronically signed.

Hassan M. Bouchareb
Engineer
Environmental Analysis and Outcomes Division

Cc: Deepa de Alwis, MPCA
Cory Boeck, MPCA
Frank Kohlasch, MPCA
Agency Interest ID 2504

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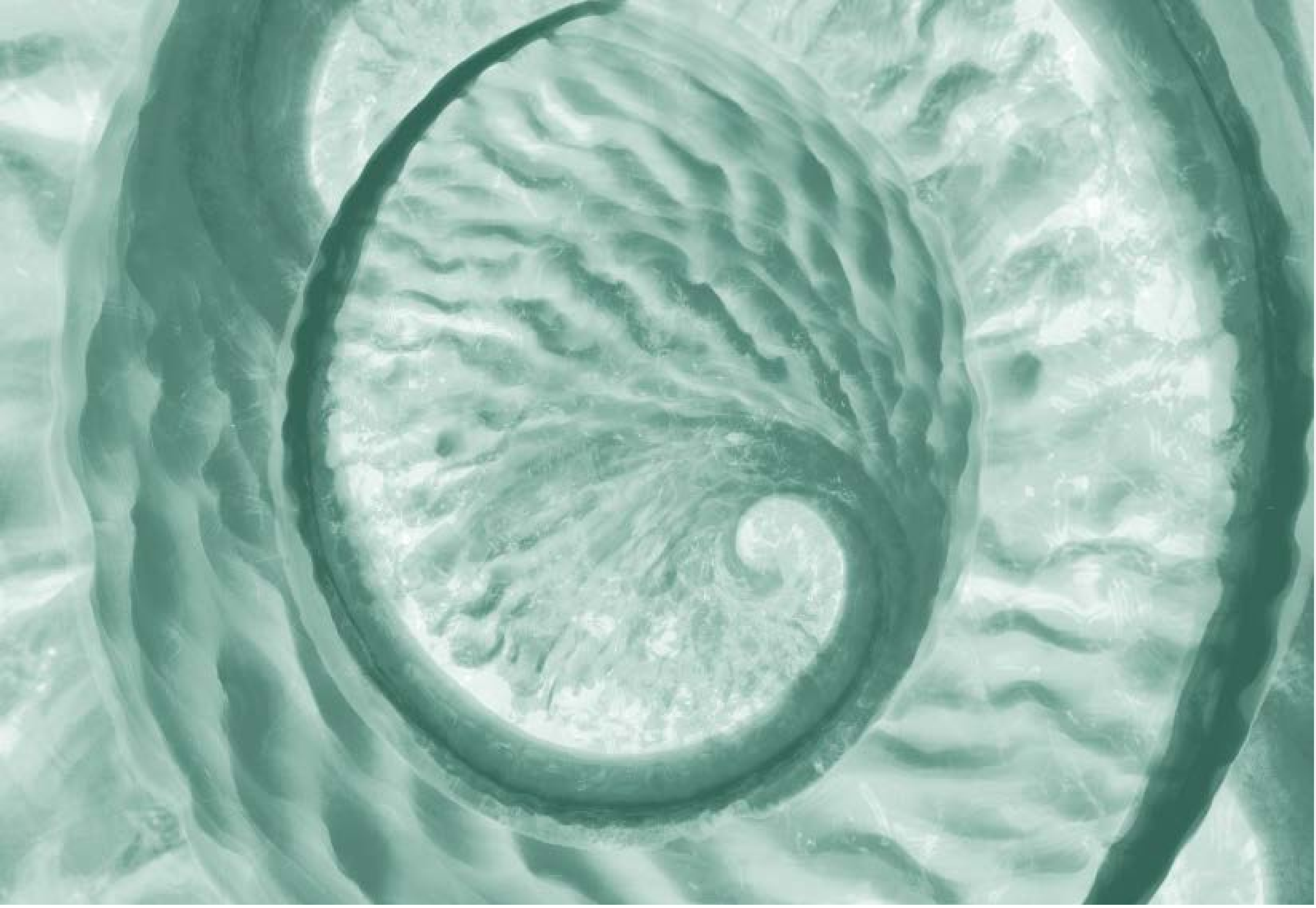
[1] **U.S. Environmental Protection Agency.** *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 20, 2019, https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.



Four Factor Analysis

City of Virginia Department of Public Utilities
Virginia, Minnesota

14 July 2020
Project No.: 0542312

The business of sustainability

ERM

Document details	This document documents the four factor analysis of the nitrogen oxide (NOx) emissions from Boiler #11 located at the City of Virginia Department of Public Utilities facility in Virginia, Minnesota.
Document title	Four Factor Analysis
Document subtitle	City of Virginia Department of Public Utilities
Project No.	0542312
Date	14 July 2020
Version	FINAL
Author	Curnow
Client Name	City of Virginia

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1. INTRODUCTION

Under 40 Code of Federal Regulation Part 52 Subpart P (Subpart P) Section 51.308, states are required to develop a long-term strategy for regional haze. Each State must submit a long-term strategy that addresses regional haze visibility impairment for each mandatory Class I Federal area within the State and for those areas located outside the State that may be affected by emissions from the State. The long-term strategy must include the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress toward achieving natural visibility conditions in the affected Class I Federal area.

Subpart P, Section 51.308(f)(2)(i) requires the State to evaluate and determine the emission reduction measures that are necessary to make reasonable progress by considering four factors:

1. Cost of compliance.
2. Time necessary for compliance.
3. Energy and non-air quality environmental impacts of compliance.
4. Remaining useful life of any potentially affected emission unit.

The State Implementation Plan must include a description of the criteria it used to determine which sources or groups of sources it evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy. In considering the time necessary for compliance, if the State concludes that a control measure cannot reasonably be installed and become operational until after the end of the implementation period, the State may not consider this fact in determining whether the measure is necessary to make reasonable progress. Revisions to the Minnesota regional haze implementation plan are due to the United States Environmental Protection Agency (USEPA) by July 31, 2021, and the implementation period is 10 years to demonstrate progress toward attaining the visibility goals.

In a letter dated January 29, 2020, the Minnesota Pollution Control Agency (MPCA) requested that the Virginia Department of Public Utilities (VDPU) conduct a four-factor analysis of the nitrogen oxide (NOx) and sulfur dioxide (SO_2) emissions from Boiler #9 (EQUI 3 / EU 003) and Boiler #11 (EQUI 16 / EU 006). In subsequent conversations with the MPCA, Boiler #9 was removed from the requirement to perform the analysis since VDPU plans to be shutting the boiler down in the near future. This analysis focuses only on Boiler #11 and only for NO_x. The listing of SO_2 as a pollutant from the wood boiler that needed to be analyzed was confirmed by the MPCA to be a typographical error in the MPCA request letter. Sulfur dioxide is not a pollutant that is emitted in large quantities from wood combustion due to the low amounts of sulfur contained in the fuel source.

The Class 1 areas in proximity to VDPU are Boundary Waters Canoe Area Wilderness and Voyageurs National Park (Voyageurs). The Boundary Waters Canoe Area Wilderness is approximately 29 miles from VDPU at the closest point and over 54 miles to the center of the wilderness area. Voyageurs is approximately 54 miles from VDPU at the closest point and over 67 miles to the center of the park. A site location map showing the VDPU and Boiler #11 stack relative to the Class 1 areas is provided in appendix A.

This report documents the four-factor analysis for controlling NO_x emissions from Boiler #11 at VDPU. A brief description of VDPU and Boiler #11 emissions is provided in Section 2 of the report. Section 3 of this report includes the four-factor analysis. Subsections in Section 3 include:

- Information on technically feasible control technology available for NO_x reductions and the cost of control.

- The time schedule necessary for implementing a control strategy is described in general terms accounting for project approval, engineering design, bidding, procurement/contracting, construction, and commissioning.
- The non-air quality impacts of compliance are identified and costs estimated to the extent possible. These include truck traffic, electrical use, solid waste generation, and water use.
- The remaining useful life of Boiler #11 is discussed in terms of the maintenance of the unit and projects for remaining life of the unit before a major overhaul or replacement is due.
- Finally, a summary of the information presented in Section 3 of the report. A general discussion of cost effectiveness is included in the summary section. This discussion is based on review of published information on the reasonableness cost per ton of NO_x and SO_2 removed as related to visibility improvement.

Finally, a summary of the four-factor analysis is presented in Section 4 of the report. A general discussion of cost effectiveness is included in the summary section. This discussion is based on review of published information on the reasonableness cost per ton of NO_x removed as related to visibility improvement.

2. PLANT DESCRIPTION

The VDPU operates a co-generation facility for the city of Virginia. The facility has the ability to generate electricity and steam. If electricity is generated, it would be sold to the electrical grid. Steam is used for space heating of nearby businesses, schools, and residences. The VDPU is considered a district heating plant and is located in downtown Virginia, in close proximity to its steam customers.

VDPU operates in accordance with a federal Part 70 Permit number 13700028-101, issued on March 21, 2019. The emission units at the facility consist of two coal-fired boilers Boiler #7 (EQUI 2) and Boiler 9 EQUI 3) [formerly known as EU001 & EU003], a natural gas-fired boiler Boiler #10 (EQUI 4) [formerly known as EU004], a wood-fired boiler Boiler #11 (EQUI 16) [formerly known as EU006], fuel storage and transfer systems, and ash handling systems.

On May 11, 2020 a permit modification application was submitted to the MPCA which included the planned decommissioning of coal-fired Boiler #9. The permitting to remove Boiler #9 from the operating permit is currently on hold with the MPCA, however, VDPU considers the boiler permanently retired. The boiler is currently not operational due to mechanical issues. Furthermore, the air operating permit will not allow Boiler #9 to be operated past September 2020 because the stack height has not been raised which was a condition of demonstrating compliance with the 1-hour SO_2 national ambient air quality standard. Boiler #9 has not been operated since April 30, 2019. Because Boiler #9 is effectively retired, it is not included in the four factor analysis.

Boiler #11 was permitted in 2005 and was required to demonstrate Best Available Control Technology (BACT) and compliance with the National Ambient Air Quality Standards in place at that time (Permit No. 13700028-005). A gas burner was permitted (Permit No. 13700028-011) and installed in 2015 to assist in stabilizing combustion to lower carbon monoxide (CO) emissions. Due to the fluctuation of the moisture content of the wood fuel being received the combustion efficiency was experiencing swings which lead to CO emissions exceeding permit limits too frequently.

Boiler #11 uses selective non-catalytic reduction for NO_x control and a multi-cyclone followed by an electrostatic precipitator for particulate matter control. The boiler is also equipped with an opacity monitor, NO_x monitor, and CO monitor.

2.1 Nitrogen Oxide Emissions

Selective Non-Catalytic Reduction (SNCR) was determined to be BACT when Boiler #11 was originally permitted in 2005. A review of recent NO_x monitor reading information is listed in Table 1.

Table 1: Continuous NO_x Emission Monitor for Boiler #11

Value Description	NO_x (ppm)	NO_x (lb/MMBtu)
Minimum	39.4	0.094
Maximum	80.2	0.175[1]
Range[2]	40.8	0.081
Average	54.1	0.121

1 Permit limit for Boiler #11 is 0.15 lb/MMBtu based on a 30-day average. The value show in this table is one instance in time not a 30 day average.

2 Range is the difference between the highest (maximum) and the lowest (minimum) within a set of numbers.

The potential emissions of NO_x for Boiler #11 while burning wood are 34.5 pounds and hour and 120 tons per year. The NO_x emissions from wood combustion are higher than if wood and natural gas combustion were occurring simultaneously. When both wood and natural gas are being combusted in Boiler #11 the potential NO_x hourly emission rate is 27.11 pounds and the potential annual emission rate is 119 tons.

The potential and actual emission rates for NO_x while burning natural gas are based on USEPA AP-42 Emission Factors. The actual emission rates for NO_x are based on the CEM. The potential NO_x emission rate is based on a permit limit.

2.2 Historical Nitrogen Oxide Emissions Boiler #11

The actual annual NO_x emissions for Boiler #11 have decreased each year from 2016 to 2019, during which time the average annual emissions were 63.21 tons per year (tpy). Table 2 provides the actual annual NO_x emission rates from 2016 to 2019 for Boiler #11.

Table 2: Historical NO_x Emissions for Boiler #11

Year	NO_x (tpy)
2016	89.9
2017	82.84
2018	42.03
2019	38.05

3. FOUR-FACTOR ANALYSIS

The following is the four-factor analysis. The following subsections present information on the cost of supplemental NO_x control, the time necessary to implement controls, the energy and non-air quality environmental impacts of implementing controls, and the remaining useful life of Boiler #11.

3.1 Nitrogen Oxide Control Technology

A BACT analysis was completed for Boiler #11 when it was initially permitted in 2005. That analysis indicated that SNCR and a NO_x emission rate of 0.15 pounds per million (MM) British thermal units was

BACT. An excerpt from the technical support document that was attached to the operating permit is provided below.

MPCA Technical Support Document, Permit Action Number: 13700028-005 Page 17 of 64, 7/11/2005

> *Nitrogen oxide controls from the RBLC database records indicate a wide range of technologies as BACT, including no control, combustion control, SNCR and SCR. Again the most stringent control, SCR appears in the permit for RBLC record OH-0269, however that facility has not been constructed and the permit has expired. BACT emission rates range from 0.15 to 0.40 pounds per million Btu, excluding OH-0269 which has not been constructed. The lowest BACT emission rate for a constructed and operating facility is 0.15 lbs/MMBtu from the District Energy St. Paul facility, which employs SNCR technology.*

In August 2010 the EPA published Documentation for Integrated Planning Model (IPM) Base Case that included NO_x emission control information prepared by an engineering firm Sargent and Lundy (EPA 2020) https://www.epa.gov/airmarkets/documentation-integrated-planning-model-ipm-base-case-v410. Sargent and Lundy performed a complete bottom-up engineering reassessment of the cost and performance assumptions NO_X emission controls for large utility coal fired boilers. The study is not directly relatable to smaller wood boiler, but the identified control technologies available for NO_x control would be the same.

Available control options identified are:

- Low NO_x burner (LNB) without over fire air (OFA),
- LNB with OFA,
- OFA
- Selective Catalytic Reduction (SCR)
- SNCR

A new search of the United States Environmental Protection Agency RACT/BACT/LAER Clearinghouse (RBLC) was conducted on June 30, 2020, to identify what NO_x control strategies are in place for wood-fired/natural gas boilers around the country and what emission levels represent the BACT. BACT limits are emission rates and are determined on a case-by-case basis. The BACT emission rates are used in this report for comparison purposes only and do not represent an applicable standard.

A RBLC search for Process Type 12.120 Industrial Boiler firing Biomass (includes wood and wood waste) and Process Type 11.120 Utility and Large Industrial Boiler firing Biomass (includes wood and wood waste) for January 1, 2010 through June 30, 2020 found 19 entries. Of the 19 entries found in the RBLC 10 were noted as having SNCR and 7 indicated SCR. The seven entries that indicated SCR was being used for control, only one, Berlin Station LLC, which has a rated capacity of 1,013 Million British thermal units (MMBtu)/hour (over 4 times large than Boiler #11) has been built and is operating. The Berlin Station boiler was the only boiler able to be confirmed was actually built with SCR. The boiler was required to comply with the Lowest Achievable Emission Rate (LAER) requirements. The Boiler's noted as having SCR are much larger in capacity (464 MMBtu/hour to 1,200 MMBtu/hour) than Boiler #11 (230 MMBtu/hour). The other entries found were listed as having low NO_x burners. Some boilers also indicated over fire air as part of the boiler design. A summary of the RBLC entries is attached as Appendix B.

LNB - Low NO_x burners control the fuel and air mixture in order to create larger and more branched flames. This reduces the peak flame temperature and in turn reduces NO_x formation.

Over Fire Air Systems - Additional NO_x reduction can be achieved by integrating staged combustion (overfire air) into the overall system. OFA can be used by itself but is most often used in conjunction with other NO_x reduction systems.

SNCR - Like the SCR system, SNCR also converts NO_x into nitrogen and water. However, no catalyst is used, instead the reagent is injected at a high temperature.

SCR – SCR uses a liquid reducing agent in combination with a catalyst to convert NOx into nitrogen and water. The reducing agent most commonly used is ammonia.

3.1.2 LNB

The wood fired boiler is a stoker boiler which means a solid fuel (in this case wood) is mechanically fed into the combustion chamber and the fuel sits on top of a grate during combustion. The wood that is added is in chip form which is around 3 inches in size. LNB is not a fuel delivery option for this type of a solid fuel. LNB is not technically feasible and eliminated from additional discussion for wood combustion.

The natural gas burners, installed in 2015 to stabilize combustion are LNB. Natural gas is being used to manage the moisture content of the wood-fuel source. Natural gas is not the primary fuel and not the focus of this analysis.

3.1.3 OFA

OFA system is a design feature of boilers to ensure adequate air to promote combustion efficiency. In Boiler #11, air for combustion is supplied from two separate sources, undergate air and overfire air. The undergate air supplies 60 percent of the required combustion air while the OFA makes up the remaining 40 percent. The OFA system provides combustion air to a serious of fixed nozzles that penetrate the furnace front and rear walls. There are three elevations of nozzles on the front wall and four elevations of nozzles on the rear wall. The nozzles are optimized to inject air above the grate into a zone where suspension burning takes place. Different nozzle elevations are used to optimize combustion while minimizing emissions from combustion. Both systems are required to be operating when wood is being combusted.

A portion of the operator's manual provided by Foster Wheeler, which provides a detailed description of the OFA system is provided in Appendix C. The air permit for Boiler #11 does not list OFA as a pollution control device because it is considered a factor of boiler design not an add-on control system.

Compliance with 40 Code of Federal Regulation Part 63 Subpart DDDD National Emission Standards for Hazardous Air Pollutants for Major Sources; Industrial, Commercial, and Institutional Boilers and Process Heater more commonly referred to as "Boiler MACT" requires Boiler #11 to be tuned annually. The tune-ups focus on boiler efficiency, which is related to air emissions.

3.1.4 SNCR

Boiler #11 has a SNCR system for NO_x reduction, and as such no additional discussion on this technology is provided since it is already in use.

3.1.5 SCR

SCR is the highest-performing control option currently available. According to the USEPA Air Pollution Control Technology Fact Sheet for SCR (EPA-452/F-03-032), SCR is capable of NO_x reduction efficiencies in the range of 70 to 90% (ICAC, 2000). A copy of the USEPA fact sheet is provided in Appendix D. Higher reductions are noted by USEPA as possible but generally not cost-effective. SCR makes use of a catalyst with ammonia injection. The catalyst improves the efficiency of the chemical reduction of NO_x by ammonia. The SCR is designed to evenly distribute the flow of NO_x across a catalyst surface, and provide thorough mixing of the injected ammonia to facilitate reduction and thus removal of NO_x. The catalyst requires gas at a sufficient temperature for the chemical reaction to occur. The boiler exhaust gas also requires particulate removal prior to the SCR to prevent fouling of the catalyst.

The potential use of SCR for control of NO_x from the Boiler #11 was evaluated as BACT when the boiler was originally permitted in 2005. The BACT analysis completed as part of the 2005 permit action indicated that SCR was an infeasible NO_x control option for a wood-fired boiler. The reason the technology was considered infeasible was because of the higher levels of silicates and other constituents found in biomass fuels which lead to rapid fouling of the catalyst bed, greatly reducing the effectiveness of the SCR system, and leading to significant down time and expense in replacing the catalyst.

The RBLC review completed for this analysis did note some wood-fired boilers that have been permitted with SCR. The boilers listed as using SCR for NO_x control are all much larger than Boiler #11 and most likely, operate at a higher capacity factor. Two of the entries that cited SCR were noted the basis for the technology as a requirement to permit at LAER. Boiler #11's primary function at VDPU is to serve the district heating system. VDPU does have some demand for steam in the summer but the majority of the steam production is during the heating season. The VDPU steam customer base continues to decrease as some former entities are relocating outside of the service area or transitioning to their own onsite steam production/heat production.

3.2 Cost Summary

SCR is the only NO_x reduction technology reviewed for cost since Boiler #11 already uses SNCR and the boiler design includes OFA. Low NO_x burners are not applicable to wood. The natural gas fired combustion stabilization burners are low NO_x but the combustion stabilizing burners are not part of this assessment. No other technology was found for application to this boiler system.

In order for an SCR to work on Boiler #11, the current ESP system would need to be replaced with a hot side ESP or, as an alternative, the air stream could be reheated to achieve sufficient temperature for the catalyst reaction. Catalysts require temperatures ranging from 480 degrees Fahrenheit (°F) to 800°F (ICAC, 1997). The exhaust temperature entering the existing ESP is at about 400 °F and would not be expected to change significantly upon the exit of the ESP.

As indicated earlier, SCR is typically applied to large coal and natural gas fired electrical utility boilers sized larger than what VDPU operates. The fact sheet does say SCR can be effective for large industrial boilers if the capacity factor is high enough. USEPA only refers to applying SCR technology to coal and natural gas fired boilers.

USEPA directly states that capital costs for SCR are significantly higher than other types of NOx controls due to the large volume of catalyst that is required. The cost of the catalyst is listed as $283/cubic foot ($ft^3$). In addition, retrofitting SCR to an existing unit can increase costs by over 30 percent (EPA, 2002).

Table 3 summarizes the cost of retrofitting Boiler #11 with an SCR NO control system. Costs are based on the USEPA "Air Pollution Control Technology Fact Sheet" for SCR, Table 1a Summary of Cost Information in $/MMBtu/hr (1999 Dollars) for Industrial Oil, Gas, and Wood boilers. The fact sheet is included as Appendix D.

Table 3: Boiler #11 SCR NO_x Control Cost Estimate Summary

Parameter	SCR
Capital Cost	$1,150,000
30% Retrofit Add-on	$345,000
O&M Cost	$103,500
Annual Cost	$161,000
SCR Subtotal (1999 $)	$1,759,500
SCR Subtotal Adjusted for 2020 $[a]	$2,707,803
Pre-heater for exhaust[b]	Cost not available
Emission reduction (85% total which is 53.2% above the existing SNCR system at 31.8%)	53.2%
Emission reduction[c] (tpy)	42.07
Cost of emission reduction ($/ton)	$64,364+

a According to the Bureau of Labor Statistics consumer prices in 2017 were 47.13% higher than in 1999. The inflation rate between 2017 and 2020 averaged 1.51% per year.

b Preheater for exhaust in lieu of a hot side ESP. The cost for the preheater was not available but listed in the table in order to identify it as another cost with both capital and operating impacts.

c Emission reduction is based on 2016 emissions of 89.9 tons of NO_x which could be reduced by another 53.2% potentially by retrofitting Boiler #11 with SCR for NO_x reduction.

The cost to retro fit Boiler #11 with SCR would be $64,364 per ton of NO_x removed. That value does not include the cost to increase the heat of the ESP exhaust to a sufficient temperature for the catalyst. Since the dissolution of the Xcel Power Purchase Agreement for renewable power, the wood boiler has seen a reduction in use as evident in the summary of historical actual emissions. The trend of reduced operation for Boiler #11 is expected to continue.

3.3 Time to Implement NO_x Controls

To implement SCR would involve the following steps and durations:

- Budgetary design and project approval (12 months),
- Detailed engineering design and bid documents (6-9 months),
- Bid solicitation, evaluation and selection (3-4 months),
- Procurement/contracting (3-4 months),
- Construction (6-10 months), and
- Commissioning (2-3 months).

This leads to an overall schedule of 32-42 months from concept to operation.

3.4 Non-Air Quality Impacts

This section outlines in general terms the non-air quality related impacts that would result from implementing SCR on Boiler #11. Table 4 shows the impacts in general terms. For example, SCR uses a catalyst which are made from various ceramic materials such as titanium oxide or oxides of base metals (such as vanadium, molybdenum and tungsten), zeolites, or various precious metals. Mining to obtain catalyst materials has environmental implications

Table 4: Impacts of Potential NO_x Add-on Control Technologies for Boiler #11

Technology	SCR
Electrical Energy Consumption	Yes
Transportation Impacts	Yes
Solid Waste Generation	Yes
Increased Water Consumption	Yes

In addition, retrofitting Boiler #11 to support SCR will result in greenhouse gas (GHG) emissions from, construction, truck traffic, material manufacturing, and electrical use. Assuming that the electricity to power the control systems is from some fossil fuel-fried generation, then the increased electrical demand would result in GHG emissions.

3.5 Remaining Useful Life

Boiler #11 began operating in 2006 and the expectation is that it will last about 25 years with proper maintenance. That means the remaining useful life of Boiler #11 is greater than 10 years.

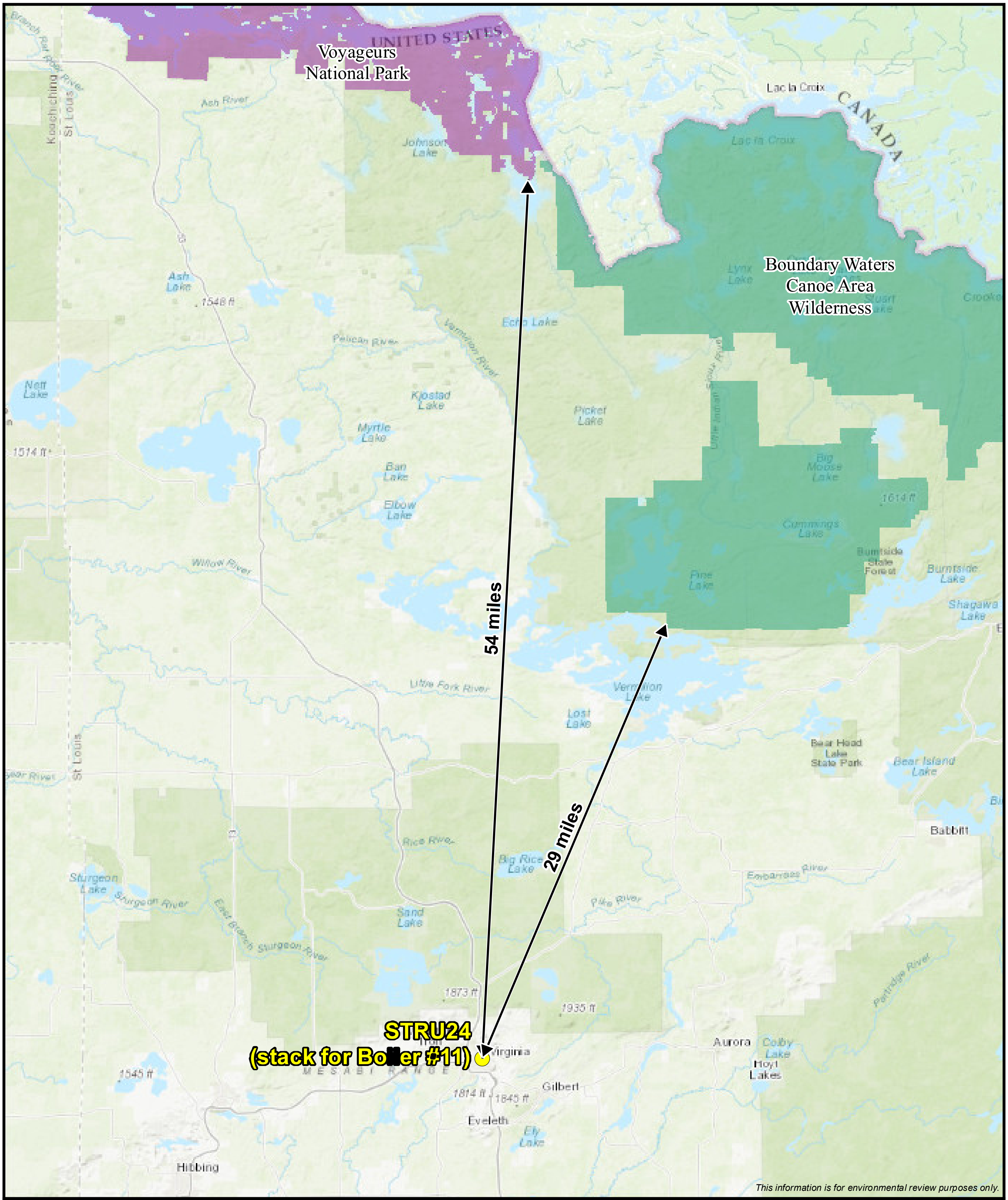
4. SUMMARY

Review of available information suggests that the cost criteria for visibility improvement is less than that for BACT; however, the target values for economic feasibility are generally not published and are evaluated on a case-by-case basis. The USEPA Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period (EPA-457/P-16-001, July 2016) provides guidance for states to establish control evaluation criteria, such as:

> "*…measures that cost less than $X/ton and that result in either (1) a visibility benefit greater than Y deciview at the most impacted Class I area or (2) cumulative visibility benefits across multiple affected Class I areas greater than Z deciview.*"

In the case of additionally controlling NO_x emissions from the Boiler #11 at VDPU, the only available technology would be to replace the SNCR system with SCR. The cost of a SCR system has been calculated to be to the SNCR is over $63,364 per ton of NO_x removal. This level of cost effectiveness would not be considered cost effective for BACT control, and should be considered cost-prohibitive for visibility protection.

APPENDIX A SITE LOCATION MAP



● STRU Stack
🟩 Boundary Waters Canoe Area Wilderness
🟪 Voyageurs National Park

N

0 2.5 5 Miles

Virginia Department of Public Utilities
Site Location Map
Four Factor Analysis

ERM

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APPENDIX B RACT/BACT/LAER SUMMARY

Appendix B
Reasonably Available Control Tecnology, Best Available Control Technology, Lowest Available Emission Rate Clearinghouse
RBLC Database Summary - EPA Database Accessed on June 30, 2020
Wood-Fired Boilers

RBLC ID	Company	Boiler Size (MMBtu/hr)	Pollutant	Limit	Units	Technology	Basis For Limit	Permit Issuance Date	Process Type[1]
ME-0040	Robbins Lumber, Inc.	167.3	NO_x	25.1	lb/hr	Flue Gas Recirculation (FGR)/Selective Non-catalytic Reduction (SNCR)	BACT	6/30/2017	12.120
MI-0425	Arauco North America Grayling Particleboard	110	NO_x	95	lb/hr	Good combustion practices, low NO_x burners (LNB)	BACT	5/9/2017	12.120
MI-0421	Arauco North America Grayling Particleboard	110	NO_x	95	lb/hr	Good combustion practices, LNB	BACT	8/26/2016	12.120
SC-0149	Klausner Holding USA, Inc.	120	NO_x	0.14	lb/MMBtu	SNCR	Other	1/3/2013	12.120
FL-0332	Highlands Envirofuels (HEF), LLC Highlands Biorefinery and Cogeneration Plant	458.5	NO_x	0.1	lb/MMBtu	SNCR with urea or NH_3 injection, and LNB	BACT	9/23/2011	12.120
FL-0322	Southeast Renewable Fuels (SRF), LLC Sweet Sorghum-to-Ethanol Advanced Biorefinery	536	NO_x	0.1	lb/MMBtu	Good combustion practices, SNCR, Selective Catalytic Reduction (SCR), or combination with urea or NH_3 injection	BACT	12/23/2010	12.120
AR-0161	Sun Bio Material Company	1,200	NO_x	0.06	lb/MMBtu	SCR	BACT	9/23/2019	11.120
FL-0359	US Sugar Corporation	1,077	NO_x	0.1	lb/MMBtu	SNCR (NH_3 injection)	BACT	11/29/2016	11.120
KS-0034	Abengoa Bioenergy Biomass of Kansas (ABBK)	500	NO_x	0.3	lb/MMBtu	SCR and Over-fire system (OFA)	BACT	5/27/2014	11.120
CA-1225	Sierra Pacific Industries	468	NO_x	0.13	lb/MMBtu	SNCR	BACT	4/25/2014	11.120
VT-0039	North Springfield Sustainable Energy Project, LLC	464	NO_x	0.03	lb/MMBtu	Bubbling fluidized bed boiler design and SCR	BACT	4/19/2013	11.120
GA-0141	Ogethorpe Power Corporation Warren County Biomass Energy Facility	341	NO_x	0.1	lb/MMBtu	SNCR	BACT	12/17/2010	11.120
VT-0037	Beaver Wood Energy Fair Haven, LLC	482	NO_x	0.03	lb/MMBtu	Good combustion control and SCR	BACT	2/10/2012	11.120
ME-0037	Verso Bucksport, LLC	817	NO_x	0.15	lb/MMBtu	SNCR	BACT	11/29/2010	11.120
CA-1203	Sierra Pacific Industries	335.7	NO_x	80	ppm	SNCR	BACT	8/30/2010	11.120
NH-0018	Berlin Station, LLC Burgess Biopower	1,013	NO_x	0.06	lb/MMBtu	SCR with NH_3 injection[2]	LAER	7/26/2010	11.120
CT-0156	NRG Energy	600	NO_x	0.06	lb/MMBtu	Regenerative SCR	LAER	4/6/2010	11.120
AL-0250	Boise White Paper, LLC	435	NO_x	0.3	lb/MMBtu	LNB	BACT	3/23/2010	11.120
TX-0553	Lindale Renewable Energy, LLC	1,256	NO_x	0.15	lb/MMBtu	SNCR	BACT	1/8/2010	11.120

EPA Website: https://cfpub.epa.gov/rblc/index.cfm?action=Search.BasicSearch&lang=en

[1] The process codes searched were 12.100 Industrial-size boilers/furnaces - Solid Fuel & Solid Fuel Mixes (> 100 MMBtu/hr to 250 MMBtu/hr) and 11.120 - Utility - and Large Industrial-Size Boilers/Furnaces (>250 MMBtu/hr) -

[2] This entry is the only facility listed in the RBLC database under the process categories searched, that has been confirmed to have been built and is using an SCR for NO_x control.

Notes:

The terms "RACT," "BACT," and "LAER" are acronyms for different program requirements under the NSR program.

RACT, or Reasonably Available Control Technology, is required on existing sources in areas that are not meeting national ambient air quality standards (i.e., non-attainment areas).

BACT, or Best Available Control Technology, is required on major new or modified sources in clean areas (i.e., attainment areas).

LAER, or Lowest Achievable Emission Rate, is required on major new or modified sources in non-attainment areas.

APPENDIX C EXCERPTS FROM FOSTER WHEELER OPERATORS MANUAL

The grate is fed onto the grate by means of two pneumatic fuel distributors situated on the furnace front wall. These are located above the grate and are evenly spaced across the width of the boiler. Each distributor receives litter from a metering feeder and blows it into the furnace using a variable pressure air stream.

The feeders are set up using a pulse air, rotating damper to regulate the front to back fuel trajectory onto the grate. Conveying air used by the feeders is supplied by a separate distributor air fan.

l) Fuel Feeders

The boiler is equipped with two variable speed twin screw feeders that are used to regulate fuel feed to each pneumatic distributor. These are located above and in close proximity to each fuel distributor.

Biomass fuel is metered into the boiler at a controlled rate set by load demand.
The feeders are supplied with integral fuel bins that receive biomass from the plant conveyor.

m) Primary Air System (HTUsee Air & Flue Gas System DescriptionUTH)

A single variable speed motor driven FD fan provides combustion air to the grate. The fan is furnished with an inlet filter, venturi metering section and inlet silencer. Airflow control is split ranged using variable speed with inlet damper control at low load. The output of the fan is regulated from load demand from the combustion control system.

Air discharged from the fan is heated in the undergrate air heater prior to entering the undergrate air plenums.

n) Secondary Air System (TUsee Air & Flue Gas System DescriptionUTH)

A single variable speed motor driven FD fan provides combustion air to the overfire air nozzles above the grate. The fan is furnished with an inlet duct, venturi metering section, intake silencer and inlet control damper. Airflow control is split ranged using variable speed with inlet damper control at low load. The output of the fan is regulated from load demand from the combustion control system.

Discharge air is heated and directed to a series of overfire air nozzles on the front and rear furnace walls.

o) Distributor Air Fan

A single, constant speed distributor air fan is furnished to supply ambient air to the fuel distributors. The fan is set up to supply a constant amount of air and is unregulated by the operator.

General

The following description should be read in conjunction with drawing No. 113925V-0202 Air & Flue Gas P&ID.

Note:

FWL terminal points are designated as "TP FWL".

Combustion Air System

Air for combustion is supplied from two separate sources, undergrate air and overfire air. Each system is sized to deliver approximately 60% and 40% respectively of the required total combustion air. It is necessary that both systems be in operation to operate the boiler when firing biomass fuel.

Undergrate air

The undergrate air system provides combustion air to the under the grate air zones. A forced draft fan delivers ambient air to the grate taken from inside the building via an intake duct. The incoming air stream to the fan is metered through a venturi section 11FE-510, equipped with flow transmitter 11FT 510 (by others) and flow switch 11FSH 510 (by others). An intake silencer 11EDS 511 is furnished for noise attenuation downstream of the metering venturi.

An inlet louver damper 11EJM 511is furnished for low load control of airflow. This is driven by air operated actuator 11FY 510 in response to a 4-20mA control signal from the DCS combustion controls. The actuator is provided with open/closed limit switches 11ZSL510/ZSH 510 for proof of closed and purge positions.

The variable speed undergrate air fan is driven by an electric motor, 11MV 510 equipped with winding temperature thermostats. The fan is also equipped with bearing temperature monitors 11TE 510A/B.

The FD fan is equipped with a variable speed drive for discharge capacity control that is spilt ranged for operation with the inlet louver control damper. Fan speed is controlled from the characterized 4-20mA combustion control signal.

Pressure at the FD fan discharge is monitored by pressure transmitter 11PT 510 prior to being directed through a tubular air heater 11ESE 510 that is utilised to preheat the undergrate air. This is necessary with all high moisture fuels for optimum combustion conditions. The temperature of air leaving the air heater is unregulated and varies with load. Temperature is measured by transmitter 11TT 512.

The grate is divided into three separate air zones from front to back. These, in turn are subdivided into LH and RH sections for a total of six independent zones. Air to each zone can be biased by individual manual inlet dampers. Control of these dampers allows the

operator to manually bias the air split, front to back and side to side for optimum burning and emissions control.

Thermocouples 11TE 721A/B/C & 11TE 722 A/B/C are provided on the underside of the grate for temperature monitoring and alarm purposes.

Overfire Air

The overfire air system provides combustion air to a series of fixed nozzles that penetrate the furnace front and rear walls. There are three elevations of nozzles on the front wall and four elevations on the rear wall (see DSCo. Manual for details). These are optimized during commissioning and set up to inject air above the grate into a zone where suspension burning takes place. Different nozzle elevations are selected in order to provide optimum combustion conditions with minimum emissions.

Secondary air is drawn from inside the boiler building through an intake duct. The duct is equipped with a venturi section 11FE 515 and transmitter 11FT 515 (by others) for flow metering purposes. A silencer 11EDS 510 is provided on the fan intake for noise attenuation purposes.

An inlet louver damper 11EJM 510 is furnished for low load control of airflow. This is driven by air operated actuator 11FY 515 in response to a 4-20mA control signal from the DCS combustion controls. The actuator is provided with open/closed limit switches 11ZSL 515/ZSH 515 for proof of closed and purge positions.

The overfire air fan is driven by a variable speed electric motor 11MV 515 equipped with winding temperature thermostats. The motor is also equipped with bearing temperature detectors TE-A-09-006A/006B.

The fan is equipped with inboard and outboard bearing temperature detectors 11TE 515A/B.

The overfire air fan is equipped with a variable speed drive for discharge capacity control that is spilt ranged for operation with the inlet louver control damper. Fan speed is controlled from the characterized 4-20mA combustion control signal.

Pressure at the overfire air fan discharge is monitored by pressure transmitter 11PT 515 prior to being directed through a tubular air heater 11ESE 511 that is utilised to preheat the overfire air. The temperature of air leaving the air heater is unregulated and varies with load. Temperature is measured by transmitter 11TT 517.

Preheated air is routed through a series of ducts to the front and rear overfire air nozzles into the furnace. Isolation dampers are provided on the nozzles for operational flexibility since some nozzles, or complete nozzle elevations may not be used during normal operation.

APPENDIX D USEPA AIR CONTROL TECHNOLOGY FACT SHEET

EPA-452/F-03-032

Air Pollution Control Technology Fact Sheet

Name of Technology: Selective Catalytic Reduction (SCR)

Type of Technology: Control Device - Chemical reduction via a reducing agent and a catalyst.

Applicable Pollutants: Nitrogen Oxides (NOx)

Achievable Emission Limits/Reductions: SCR is capable of NOx reduction efficiencies in the range of 70% to 90% (ICAC, 2000). Higher reductions are possible but generally are not cost-effective.

Applicable Source Type: Point

Typical Industrial Applications: Stationary fossil fuel combustion units such as electrical utility boilers, industrial boilers, process heaters, gas turbines, and reciprocating internal combustion engines. In addition, SCR has been applied to nitric acid plants. (ICAC, 1997)

Emission Stream Characteristics:

a. **Combustion Unit Size:** In the United States, SCR has been applied to coal- and natural gas-fired electrical utility boilers ranging in size from 250 to 8,000 MMBtu/hr (25 to 800 MW) (EPA, 2002). SCR can be cost effective for large industrial boilers and process heaters operating at high to moderate capacity factors (>100 MMBtu/hr or >10MW for coal-fired and >50 MMBtu/hr or >5MW for gas-fired boilers). SCR is a widely used technology for large gas turbines.

b. **Temperature:** The NOx reduction reaction is effective only within a given temperature range. The optimum temperature range depends on the type of catalyst used and the flue gas composition. Optimum temperatures vary from 480°F to 800°F (250°C to 427°C) (ICAC, 1997). Typical SCR systems tolerate temperature fluctuations of ± 200°F (± 90°C) (EPA, 2002).

c. **Pollutant Loading:** SCR can achieve high reduction efficiencies (>70%) on NOx concentrations as low as 20 parts per million (ppm). Higher NOx levels result in increased performance; however, above 150 ppm, the reaction rate does not increase significantly (Environex, 2000). High levels of sulfur and particulate matter (PM) in the waste gas stream will increase the cost of SCR.

d. **Other Considerations:** Ammonia slip refers to emissions of unreacted ammonia that result from incomplete reaction of the NOx and the reagent. Ammonia slip may cause: 1) formation of ammonium sulfates, which can plug or corrode downstream components, and 2) ammonia absorption into fly ash, which may affect disposal or reuse of the ash. In the U.S., permitted ammonia slip levels are typically 2 to 10 ppm. Ammonia slip at this levels do not result in plume formation or human health hazards. Process optimization after installation can lower slip levels.

Waste gas streams with high levels of PM may require a sootblower. Sootblowers are installed in the SCR reactor to reduce deposition of particulate onto the catalyst. It also reduces fouling of downstream equipment by ammonium sulfates.

The pressure of the waste gas decreases significantly as it flows across the catalyst. Application of SCR generally requires installation a new or upgraded induced draft fan to recover pressure.

Emission Stream Pretreatment Requirements: The flue gas may require heating to raise the temperature to the optimum range for the reduction reaction. Sulfur and PM may be removed from the waste gas stream to reduce catalyst deactivation and fouling of downstream equipment.

Cost Information:

Capital costs are significantly higher than other types of NOx controls due to the large volume of catalyst that is required. The cost of catalyst is approximately 10,000 $\$/m^3$ (283 $\$/ft^3$). A 350 MMBtu/hr natural gas-fired boiler operating at 85% capacity requires approximately 17 m^3 (600 ft^3). For the same sized coal-fired boiler, the required catalyst is on the order of 42 m^3 (1,500 ft^3). (NESCAUM 2000).

SCR is a proprietary technology and designs on large combustion units are site specific. Retrofit of SCR on an existing unit can increase costs by over 30% (EPA, 2002). The increase in cost is primarily due to ductwork modification, the cost of structural steel, and reactor construction. Significant demolition and relocation of equipment may be required to provide space for the reactor.

The O&M costs of using SCR are driven by the reagent usage, catalyst replacement, and increased electrical power usage. SCR applications on large units (>100 MMBtu/hr) generally require 20,000 to 100,000 gallons of reagent per week (EPA, 2002). The catalyst operating life is on the order of 25,000 hours for coal-fired units and 40,000 hours for oil- and gas-fired units (EPA, 2002). A catalyst management plan can be developed so that only a fraction of the total catalyst inventory, rather than the entire volume, is replaced at any one time. This distributes the catalyst replacement and disposal costs more evenly over the lifetime of the system. O&M costs are greatly impacted by the capacity factor of the unit and annual versus seasonal control of NO_X.

O&M cost and the cost per ton of pollutant removed is greatly impacted by the capacity factor and whether SCR is utilized seasonally or year round.

Table 1a: Summary of Cost Information in $/MMBtu/hr (1999 Dollars) [a, b]

Unit Type	Capital Cost ($/MMBtu)	O&M Cost [d] ($/MMBtu)	Annual Cost [d] ($/MMBtu)	Cost per Ton of Pollutant Removed ($/ton)
Industrial Coal Boiler	10,000 - 15,000	300	1,600	2,000 - 5,000
Industrial Oil, Gas, Wood [c]	4,000 - 6,000	450	700	1,000 - 3,000
Large Gas Turbine	5,000 - 7,500	3,500	8,500	3,000 - 6,000
Small Gas Turbine	17,000 - 35,000	1,500	3,000	2,000 - 10,000

Table 1b: Summary of Cost Information in \$/MW (1999 Dollars) [a, b]

Unit Type	Capital Cost ($/MW)	O&M Cost [d] ($/MW)	Annual Cost [d] ($/MW)	Cost per Ton of Pollutant Removed ($/ton)
Industrial Coal Boiler	1,000 - 1,500	30	160	2,000 - 5,000
Industrial Oil, Gas, Wood [c]	400 - 600	45	70	1,000 - 3,000
Large Gas Turbine	500 - 750	350	850	3,000 - 6,000
Small Gas Turbine	1,700- 3,500	150	300	2,000 - 10,000

[a] (ICAC, 1997; NESCAUM, 2000; EPA, 2002)

[b] Assumes 85% capacity factor and annual control of NOx

[c] SCR installed on wood fired boiler assumes a hot side electrostatic precipitator for PM removal

[d] Coal and oil O&M and annual costs are based on 350MMBtu boiler, and gas turbine O&M and annual costs are based on 75 MW and 5 MW turbine

Theory of Operation:

The SCR process chemically reduces the NOx molecule into molecular nitrogen and water vapor. A nitrogen based reagent such as ammonia or urea is injected into the ductwork, downstream of the combustion unit. The waste gas mixes with the reagent and enters a reactor module containing catalyst. The hot flue gas and reagent diffuse through the catalyst. The reagent reacts selectively with the NOx within a specific temperature range and in the presence of the catalyst and oxygen.

Temperature, the amount of reducing agent, injection grid design and catalyst activity are the main factors that determine the actual removal efficiency. The use of a catalyst results in two primary advantages of the SCR process over the SNCR: higher NOx control efficiency and reactions within a lower and broader temperature range. The benefits are accompanied by a significant increase in capital and operating costs. The catalyst is composed of active metals or ceramics with a highly porous structure. Catalysts configurations are generally ceramic honeycomb and pleated metal plate (monolith) designs. The catalyst composition, type, and physical properties affect performance, reliability, catalyst quantity required, and cost. The SCR system supplier and catalyst supplier generally guarantee the catalyst life and performance. Newer catalyst designs increase catalyst activity, surface area per unit volume, and the temperature range for the reduction reaction.

Catalyst activity is a measure of the NOx reduction reaction rate. Catalyst activity is a function of many variables including catalyst composition and structure, diffusion rates, mass transfer rates, gas temperature, and gas composition. Catalyst deactivation is caused by:

- poisoning of active sites by flue gas constituents,
- thermal sintering of active sites due to high temperatures within reactor,
- blinding/plugging/fouling of active sites by ammonia-sulfur salts and particulate matter, and
- erosion due to high gas velocities.

As the catalyst activity decreases, NOx removal decreases and ammonia slip increases. When the ammonia slip reaches the maximum design or permitted level, new catalyst must be installed. There are several different locations downstream of the combustion unit where SCR systems can be installed. Most coal-fired applications locate the reactor downstream of the economizer and upstream of the air heater and particulate control devices (hot-side). The flue gas in this location is usually within the optimum temperature window for NOx reduction reactions using metal oxide catalysts. SCR may be applied after PM and sulfur removal

equipment (cold-side), however, reheating of the flue gas may be required, which significantly increases the operational costs.

SCR is very cost-effective for natural gas fired units. Less catalyst is required since the waste gas stream has lower levels of NOx, sulfur, and PM. Combined-cycle natural gas turbines frequently use SCR technology for NOx reduction. A typical combined-cycle SCR design places the reactor chamber after the superheater within a cavity of the heat recovery steam generator system (HRSG). The flue gas temperature in this area is within the operating range for base metal-type catalysts.

SCR can be used separately or in combination with other NOx combustion control technologies such as low NOx burners (LNB) and natural gas reburn (NGR). SCR can be designed to provide NOx reductions year-round or only during ozone season.

Advantages:

- Higher NOx reductions than low-NOx burners and Selective Non-Catalytic Reduction (SNCR)
- Applicable to sources with low NOx concentrations
- Reactions occur within a lower and broader temperature range than SNCR.
- Does not require modifications to the combustion unit

Disadvantages:

- Significantly higher capital and operating costs than low-NOx burners and SNCR
- Retrofit of SCR on industrial boilers is difficult and costly
- Large volume of reagent and catalyst required.
- May require downstream equipment cleaning.
- Results in ammonia in the waste gas stream which may impact plume visibility, and resale or disposal of ash.

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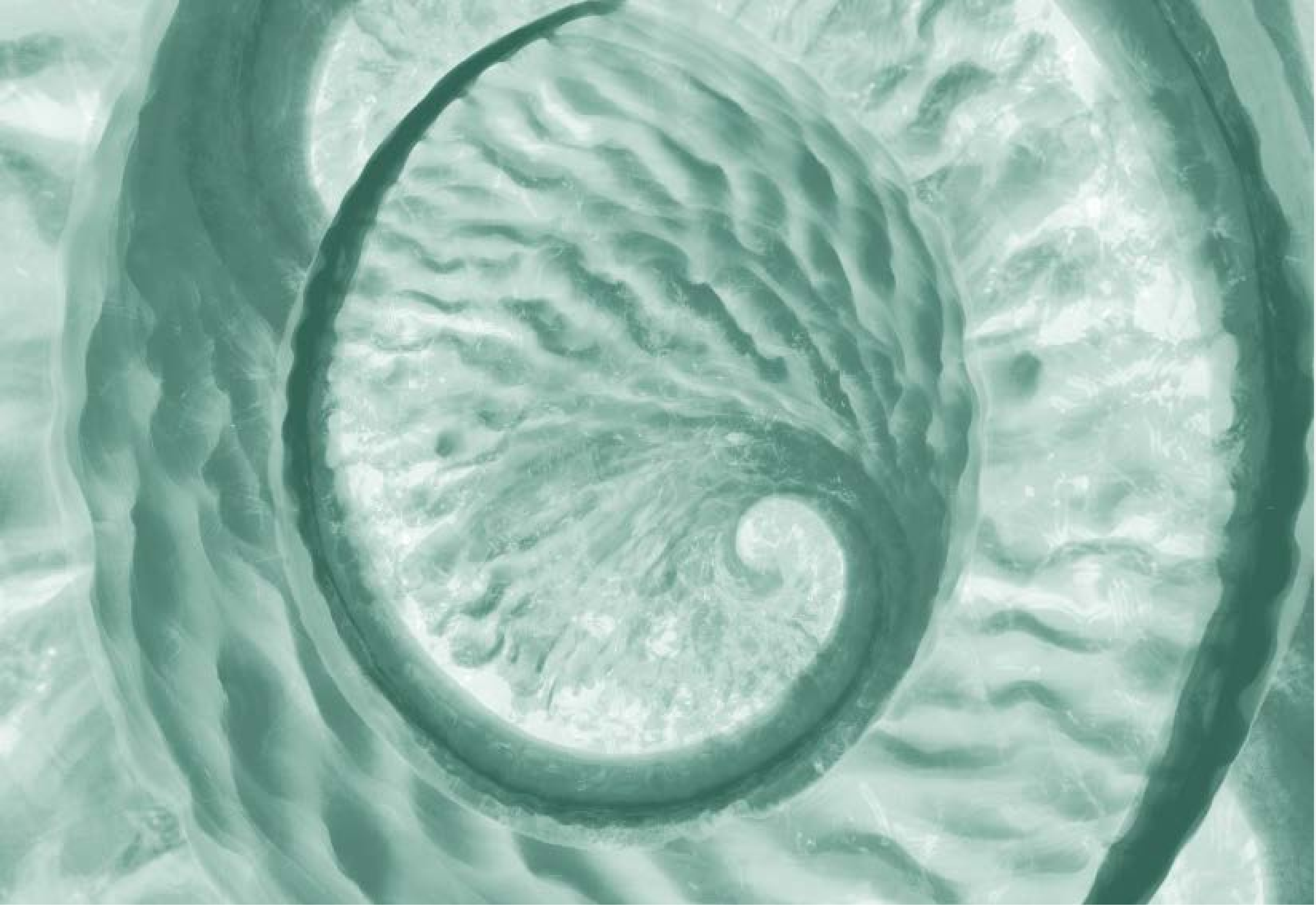

Four Factor Analysis

City of Virginia Department of Public Utilities

Virginia, Minnesota

4 June 2021

Project No.: 0542312

The business of sustainability

ERM

Document details	This document documents the four factor analysis of the nitrogen oxide (NO_x) and sulfur dioxide (SO_2) emissions from Boiler #7 and NOx emissions from Boiler #11 located at the City of Virginia Department of Public Utilities facility in Virginia, Minnesota.
Document title	Four Factor Analysis
Document subtitle	City of Virginia Department of Public Utilities
Project No.	0542312
Date	4 June 2021
Version	Final
Author	Curnow
Client Name	City of Virginia

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1. INTRODUCTION

Under 40 Code of Federal Regulation Part 52 Subpart P (Subpart P) Section 51.308, states are required to develop a long-term strategy for regional haze. Each State must submit a long-term strategy that addresses regional haze visibility impairment for each mandatory Class I Federal area within the State and for those areas located outside the State that may be affected by emissions from the State. The long-term strategy must include the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress toward achieving natural visibility conditions in the affected Class I Federal area.

Subpart P, Section 51.308(f)(2)(i) requires the State to evaluate and determine the emission reduction measures that are necessary to make reasonable progress by considering four factors:

1. Cost of compliance.
2. Time necessary for compliance.
3. Energy and non-air quality environmental impacts of compliance.
4. Remaining useful life of any potentially affected emission unit.

The State Implementation Plan must include a description of the criteria it used to determine which sources or groups of sources it evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy. In considering the time necessary for compliance, if the State concludes that a control measure cannot reasonably be installed and become operational until after the end of the implementation period, the State may not consider this fact in determining whether the measure is necessary to make reasonable progress. Revisions to the Minnesota regional haze implementation plan are due to the United States Environmental Protection Agency (USEPA) by July 31, 2021, and the implementation period is 10 years to demonstrate progress toward attaining the visibility goals.

In a letter dated January 29, 2020, the Minnesota Pollution Control Agency (MPCA) requested that the Virginia Department of Public Utilities (VDPU) conduct a four-factor analysis of the nitrogen oxide (NOx) and sulfur dioxide (SO_2) emissions from Boiler #9 (EQUI 3 / EU 003) and Boiler #11 (EQUI 16 / EU 006). In subsequent conversations with the MPCA, Boiler #9 was removed from the requirement to perform the analysis since VDPU was planning to shutdown Boiler #9 and subsequently has shutdown Boiler #9.

The four-factor analysis submitted in 2020 focused only on Boiler #11 and only for NO_x. The listing of SO_2 as a pollutant from the wood boiler that needed to be analyzed was confirmed by the MPCA to be a typographical error in the MPCA request letter. Sulfur dioxide is not a pollutant that is emitted in large quantities from wood combustion due to the low amounts of sulfur contained in the fuel source.

The Federal Land Managers (FLM) subsequently requested a four-factor analysis to be completed on Boiler #7 for NO_x and SO_2. Boiler #7 was not originally requested because during the base line year used to identify boilers to include, Boiler #7 had limited operation but that has increased since the baseline year of 2016.

The analysis completed is now updated to include Boiler #7.

The Class 1 areas in proximity to VDPU are Boundary Waters Canoe Area Wilderness and Voyageurs National Park (Voyageurs). The Boundary Waters Canoe Area Wilderness is approximately 29 miles from VDPU at the closest point and over 54 miles to the center of the wilderness area. Voyageurs is approximately 54 miles from VDPU at the closest point and over 67 miles to the center of the park. A site location map showing the VDPU relative to the Class 1 areas is provided in appendix A.

This report documents the four-factor analysis for controlling NO_x emissions from Boiler #7 and Boiler #11 at VDPU as well as controlling SO_2 from Boiler #7. A brief description of Boiler #7 and Boiler #11 emissions is provided in Section 2 of the report. Section 3 of this report includes the four-factor analysis. Subsections in Section 3 include:

- Information on technically feasible control technology available for NO_x and SO_2 reductions and the cost of control.
- The time schedule necessary for implementing a control strategy is described in general terms accounting for project approval, engineering design, bidding, procurement/contracting, construction, and commissioning.
- The non-air quality impacts of compliance are identified and costs estimated to the extent possible. These include truck traffic, electrical use, solid waste generation, and water use.
- The remaining useful life of Boiler #7 and Boiler #11 is discussed in terms of the maintenance of the unit and projects for remaining life of the unit before a major overhaul or replacement is due.
- Finally, a summary of the information presented in Section 3 of the report. A general discussion of cost effectiveness is included in the summary section. This discussion is based on review of published information on the reasonableness cost per ton of NO_x and SO_2 removed as related to visibility improvement.

Finally, a summary of the four-factor analysis is presented in Section 4 of the report. A general discussion of cost effectiveness is included in the summary section. This discussion is based on review of published information on the reasonableness cost per ton of NO_x removed as related to visibility improvement for Boilers #7 and Boilers #11. The same discussion for SO_2 is also listed for Boiler #7.

2. PLANT DESCRIPTION

The VDPU operates a co-generation facility for the city of Virginia. The facility has the ability to generate electricity and steam. If electricity is generated, it would be sold to the electrical grid. Steam is used for space heating of nearby businesses, schools, and residences. The VDPU is considered a district heating plant and is located in downtown Virginia, in close proximity to its steam customers.

VDPU operates in accordance with a federal Part 70 Permit. The emission units at the facility consist of a coal-fired boiler~~s~~ Boiler #7 (EQUI 2) [formerly known as EU001], a natural gas-fired boiler Boiler #10 (EQUI 4) [formerly known as EU004], a wood-fired boiler Boiler #11 (EQUI 16) [formerly known as EU006], fuel storage and transfer systems, and ash handling systems.

On May 11, 2020 a permit modification application was submitted to the MPCA which included the planned decommissioning of coal-fired Boiler #9 (EQUI 3). The revised operating permit that retired Boiler #9 was issued by the MPCA on March 24, 2021 (Permit Number 13700028-102).

The current operational considerations for the remaining large boilers at VDPU are listed below.

1. Boiler #10 (EQUI 4) is the primary emergency backup boiler. Boiler #10 has the quickest startup time.
2. Boiler #11 (EQUI 16) will be used as needed but most likely only if there is a problem starting Boiler #10. Although capable of burning wood, Boiler #11 will most likely burn only natural gas moving forward.

3. Boiler #7 (EQUI 2) would not be considered an emergency backup boiler. VDPU is reviewing the possibility of making Boiler #7 a limited use boiler as per the USEPA Boiler MACT definition. VDPU plans to keep Boiler #7 online in order to keep fuel options open so as not to be completely dependent on future natural gas pricing.

4. The package natural gas boilers that are being installed per permit action 13700028-102 will become the main boilers for serving the district heating system. Their smaller size is more suited for that application.

Some drivers of the change in the operation of boilers going forward are as follows:

- VDPU no longer is contracted with Xcel Energy to generate electricity.
- Essentia Health is in the process of conducting an environmental study at the site of the current hospital in Virginia. Pending the outcome of that study, Essentia would buy the hospital from the city of Virginia and build a new facility. They would probably put in their own boilers. If this were to happen, we would lose the hospital, college, and Washington Manor (a three-story elder living community).
- The steam will be shut off to approximately 100 residential customers on the north side of Virginia at the end of October 2021. Residential customers in that area are being converted to other heat sources.

2.1 Nitrogen Oxide Emissions

Boiler #7 is not equipped with a NO_x monitor nor is the boiler equipped with NO_x emission reduction technology. Stack testing completed on February 25, 2020 indicated the average NO_x emission rate was 0.34 pounds/million British thermal units (lb/MMBtu) which equates to 40.67 pounds per hour (lbs/hr) (0.0034 tons NO_x/ton Coal). The potential emissions for NO_x from Boiler #7 are 90.59 lbs/hr and 396.78 tons per year (tpy).

Selective Non-Catalytic Reduction (SNCR) was determined to be Best Available Control Technology (BACT) for NO_x when Boiler #11 was originally permitted in 2005.

A gas burner for Boiler #11 was permitted (Permit No. 13700028-011) and installed in 2015 to assist in stabilizing combustion to lower carbon monoxide (CO) emissions. The fluctuation of the moisture content of the wood fuel being received was affecting the combustion efficiency and causing large swings in CO emissions, sometimes causing the CO to be higher than the permit limit for the boiler.

Boiler #11 uses selective non-catalytic reduction (SNCR) for NO_x control and a multi-cyclone followed by an electrostatic precipitator for particulate matter control. The boiler is also equipped with an opacity monitor, NO_x monitor, and CO monitor.

A review of recent NO_x monitor reading information is listed in Table 1.

Table 1: Continuous NO_x Emission Monitor for Boiler #11

Value Description	NO_x (ppm)	NO_x (lb/MMBtu)
Minimum	39.4	0.094
Maximum	80.2	0.175[1]
Range[2]	40.8	0.081
Average	54.1	0.121

1 Permit limit for Boiler #11 is 0.15 lb/MMBtu based on a 30-day average. The value shown in this table is one instance in time not a 30 day average.

2 Range is the difference between the highest (maximum) and the lowest (minimum) within a set of numbers.

The potential emissions of NO_x for Boiler #11 while burning wood are 34.5 pounds per hour and 120 tons per year. The NO_x emissions from wood combustion are higher than if wood and natural gas combustion were occurring simultaneously. When both wood and natural gas are being combusted in Boiler #11 the potential NO_x hourly emission rate is 27.11 pounds and the potential annual emission rate is 119 tons.

2.2 Sulfur Dioxide Emissions

Boiler #7 is not equipped with a SO_2 emission reduction technology. The potential emissions for SO_2 from Boiler #7 are 142.28 pounds per hour and 623.16 tons per year. A review of recent SO_2 monitor reading information is listed in Table 2.

Table 2: Continuous SO_2 Emission Monitor for Boiler #7

Value Description	SO_2 (ppm)	SO_2 (lb/MMBtu)
Minimum	53.4	0.39
Maximum	151.9	0.85[1]
Range[2]	98.5	0.46
Average	98	0.61

1 Permit limit for Boiler #7 is 0.813 lb/MMBtu based on a 30-day average. The value show in this table is one instance in time not a 30 day average.

2 Range is the difference between the highest (maximum) and the lowest (minimum) within a set of numbers.

2.3 Historical Emissions Boiler #7 and Boiler #11

The actual annual NO_x emissions for Boiler #11 have decreased each year from 2016 to 2019, during which time the average annual emissions were 63.21 tpy. Table 3 provides the actual annual NO_x emission rates from 2016 to 2019 for Boiler #11. The use of Boiler #7 has increased in part due to the shutdown of Boiler #9 and the decreased use of Boiler #11.

Table 3: Historical Emissions for Boiler #7 and Boiler #11

Year	Boiler #7 – SO_x (tpy)	Boiler #7 – NO_x (tpy)	Boiler #11 - NO_x (tpy)
2016	39.05	23.11	89.9
2017	68.39	49.25	82.84
2018	77.25	59.64	42.03
2019	92.94	70.76	38.05

3. FOUR-FACTOR ANALYSIS

The following is the four-factor analysis. Section 3.1 presents information on the available control technologies for NO_x control for Boiler #11 and Boiler #7. Section 3.2 has the same information for SO_2 but is only for Boiler #7 since the fuels combusted in Boiler #11 are not significant sources of SO_2. Section 3.3 provides the cost of implementing the controls. Subsequent sections provide information on the time necessary to implement controls, the energy and non-air quality environmental impacts of implementing controls, and the remaining useful life of each of the boilers being reviewed.

3.1 Nitrogen Oxide Control Technology

A BACT analysis was completed for Boiler #11 when it was initially permitted in 2005. That analysis indicated that SNCR and a NO_x emission rate of 0.15 lbs/MMBtu was BACT. An excerpt from the technical support document that was attached to the operating permit is provided below.

MPCA Technical Support Document, Permit Action Number: 13700028-005 Page 17 of 64, 7/11/2005

> *Nitrogen oxide controls from the RBLC database records indicate a wide range of technologies as BACT, including no control, combustion control, SNCR and SCR. Again the most stringent control, SCR appears in the permit for RBLC record OH-0269, however that facility has not been constructed and the permit has expired. BACT emission rates range from 0.15 to 0.40 pounds per million Btu, excluding OH-0269 which has not been constructed. The lowest BACT emission rate for a constructed and operating facility is 0.15 lbs/MMBtu from the District Energy St. Paul facility, which employs SNCR technology.*

In August 2010 the EPA published Documentation for Integrated Planning Model (IPM) Base Case that included NO_x emission control information prepared by an engineering firm Sargent and Lundy (EPA 2020) https://www.epa.gov/airmarkets/documentation-integrated-planning-model-ipm-base-case-v410. Sargent and Lundy performed a complete bottom-up engineering reassessment of the cost and performance assumptions NO_X emission controls for large utility coal fired boilers. The study is not directly relatable to smaller wood boiler, but the identified control technologies available for NO_x control would be the same.

Available control options identified are:

- Low NO_x burner (LNB) without over fire air (OFA),
- LNB with OFA,
- OFA
- Selective Catalytic Reduction (SCR)
- SNCR

A new search of the United States Environmental Protection Agency RACT/BACT/LAER Clearinghouse (RBLC) was conducted on June 30, 2020, to identify what NO_x control strategies are in place for wood-fired/natural gas boilers around the country and what emission levels represent the BACT. BACT limits are emission rates and are determined on a case-by-case basis. The BACT emission rates are used in this report for comparison purposes only and do not represent an applicable standard.

A RBLC search for Process Type 12.120 Industrial Boiler firing Biomass (includes wood and wood waste) and Process Type 11.120 Utility and Large Industrial Boiler firing Biomass (includes wood and wood waste) and Process Type 12.110 Industrial Boiler firing coal and Process Type 11.110 Utility and Large Industrial Boiler firing coal for January 1, 2010 through June 30, 2020. Nineteen entries were found for wood.

Of the 19 wood entries found in the RBLC 10 were noted as having SNCR and 7 indicated SCR. The seven entries that indicated SCR was being used for control, only one, Berlin Station LLC, which has a rated capacity of 1,013 MMBtu/hour (over 4 times large than Boiler #11) has been built and is operating. The Berlin Station boiler was the only boiler able to be confirmed was actually built with SCR. The boiler was required to comply with the Lowest Achievable Emission Rate (LAER) requirements. The Boiler's noted as having SCR are much larger in capacity (464 MMBtu/hr to 1,200 MMBtu/hr) than Boiler #11 (230

MMBtu/hr). The other entries found were listed as having low NO_x burners. Some boilers also indicated over fire air as part of the boiler design.

There were 15 entries in the database for coal combustion. Of the 15 entries 5 were noted as having SNCR and 3 had SCR.

A summary of the RBLC entries is attached as Appendix B.

LNB - Low NO_x burners control the fuel and air mixture in order to create larger and more branched flames. This reduces the peak flame temperature and in turn reduces NO_x formation.

Over Fire Air Systems - Additional NO_x reduction can be achieved by integrating staged combustion (overfire air) into the overall system. OFA can be used by itself but is most often used in conjunction with other NO_x reduction systems.

SNCR - Like the SCR system, SNCR also converts NO_x into nitrogen and water. However, no catalyst is used, instead the reagent is injected at a high temperature.

SCR – SCR uses a liquid reducing agent in combination with a catalyst to convert NO_x into nitrogen and water. The reducing agent most commonly used is ammonia.

3.1.2 LNB

The Boiler #7 and Boiler #11 are both stoker boilers which means a solid fuel is mechanically fed into the combustion chamber and the fuel sits on top of a grate during combustion. The wood that is added to Boiler #11 is in chip form which is around 3 inches in size. LNB is not a fuel delivery option for these types of a solid fuel. LNB is not technically feasible and eliminated from additional discussion for wood or coal combustion.

The natural gas burners on Boiler #11 were installed in 2015 to stabilize combustion are LNB. Natural gas is being used to manage the moisture content of the wood-fuel source. Natural gas is not the primary fuel and not the focus of this analysis for Boiler #11.

3.1.3 OFA

OFA system is a design feature of boilers to ensure adequate air to promote combustion efficiency. In Boiler #11, air for combustion is supplied from two separate sources, undergate air and overfire air. The undergate air supplies 60 percent of the required combustion air while the OFA makes up the remaining 40 percent. The OFA system provides combustion air to a serious of fixed nozzles that penetrate the furnace front and rear walls. There are three elevations of nozzles on the front wall and four elevations of nozzles on the rear wall. The nozzles are optimized to inject air above the grate into a zone where suspension burning takes place. Different nozzle elevations are used to optimize combustion while minimizing emissions from combustion. Both systems are required to be operating when wood is being combusted.

A portion of the operator’s manual provided by Foster Wheeler, which provides a detailed description of the OFA system is provided in Appendix C. The air permit for Boiler #11 does not list OFA as a pollution control device because it is considered a factor of boiler design and not an add-on control system.

Boiler #7 does not have an OFA system as part of its design. It may be possible to add OFA Because OFA is a design feature as opposed to an add-on control technology it is not something that can be simply added to Boiler #7. Engineers would have to do a detailed study of the combustion and ventilation setup to determine if changes could even be made to add OFA. Since it is not an option without some detailed engineering investigation first it is not analyzed for cost.

Compliance with 40 Code of Federal Regulation Part 63 Subpart DDDDD National Emission Standards for Hazardous Air Pollutants for Major Sources; Industrial, Commercial, and Institutional Boilers and Process Heater more commonly referred to as "Boiler MACT" requires Boiler #7 and Boiler #11 to be tuned annually. The tune-ups focus on boiler efficiency, which is related to air emissions.

3.1.4 SNCR

Boiler #11 has a SNCR system for NO_x reduction, and as such no additional discussion on this technology is provided for Boiler #11 since it is already in use. SNCR is an option to add on to Boiler #7 and the cost is evaluated in section 3.2.2.

3.1.5 SCR

SCR is the highest-performing control option currently available. According to the USEPA Air Pollution Control Technology Fact Sheet for SCR (EPA-452/F-03-032), SCR is capable of NO_x reduction efficiencies in the range of 70 to 90% (ICAC, 2000). A copy of the USEPA fact sheet is provided in Appendix D. Higher reductions are noted by USEPA as possible but generally not cost-effective. SCR makes use of a catalyst with ammonia injection. The catalyst improves the efficiency of the chemical reduction of NO_x by ammonia. The SCR is designed to evenly distribute the flow of NO_x across a catalyst surface, and provide thorough mixing of the injected ammonia to facilitate reduction and thus removal of NO_x. The catalyst requires gas at a sufficient temperature for the chemical reaction to occur. The boiler exhaust gas also requires particulate removal prior to the SCR to prevent fouling of the catalyst.

The potential use of SCR for control of NO_x from the Boiler #11 was evaluated as BACT when the boiler was originally permitted in 2005. The BACT analysis completed as part of the 2005 permit action indicated that SCR was an infeasible NO_x control option for a wood-fired boiler. The reason the technology was considered infeasible was because of the higher levels of silicates and other constituents found in biomass fuels which lead to rapid fouling of the catalyst bed, greatly reducing the effectiveness of the SCR system, and leading to significant down time and expense in replacing the catalyst. The cost of adding SCR to Boiler #11 is evaluated in section 3.3.1.

The RBLC review completed for this analysis did note some wood-fired boilers that have been permitted with SCR. The boilers listed as using SCR for NO_x control are all much larger than Boiler #11 and most likely, operate at a higher capacity factor. Two of the entries that cited SCR were noted the basis for the technology as a requirement to permit at LAER. Boiler #11's primary function at VDPU is to serve the district heating system and will be relegated to backup most likely. VDPU does have some demand for steam in the summer but the majority of the steam production is during the heating season. The VDPU steam customer base continues to decrease as some former entities are relocating outside of the service area or transitioning to their own onsite steam production/heat production.

SCR is an option for Boiler #7, although Boiler #7 is a small boiler (175 MMBtu/hr) compared to the boilers in the RBLC database for utilities. The same issues with SCR discussed above for Boiler #11 exist for its use on Boiler #7 for NO_x control. The cost for SCR to Boiler #7 is evaluated in section 3.3.2.

3.2 Sulfur Dioxide Control Technology

A literature review of available control technology for coal fired boilers was conducted and two commercially available Flue Gas Desulfurization (FGD) technology options are available for removing SO_2 produced by coal-fired boilers. The two technologies identified as commercially available that could be applied to Boiler #7 are:

1. Limestone Forced Oxidation (LSFO) Scrubber, and

2. Lime Spray Dryer (LSD) Scrubber.

LSFO – LSFO is a wet FGD technology. In a wet system the exhaust gas is mixed with a liquid alkaline sorbent (typically limestone). The mixing is achieved by forcing the exhaust stream through a pool off liquid slurry or by spraying the exhaust with a liquid. This technology is commonly simply referred to as wet scrubbing. According to vendor information, a new wet scrubber can routinely achieve SO_2 removal efficiencies of 95% (Institute of Clean Air Companies [ICAC] Acid Gas/SO_2 Controls), https://www.icac.com/page/Acid_Gas_SO2_Control.

LSD – LSD is a semi-dry FGD technology that uses a spray dyer absorber. In dry FGD systems, the exhaust stream is brought into contact with the alkaline sorbent in a semi-dry state through use of a spray dryer. The removal efficiency is dependent on the amount of sulfur in the coal. This technology is often referred to as dry scrubbing or dry sorbent injection. A fabric filter/baghouse is required downstream of the scrubber to collect the sorbent used to absorb the SO_2. This technology is commonly referred to as a spray dryer.

In addition to the literature review, a search of the USEPA RACT/BACT/LAER Clearinghouse (RBLC) database for Process Type 12.110 Industrial Boiler firing coal and Process Type 11.110 Utility and Large Industrial Boiler firing coal for January 1, 2010 through June 30, 2020 was conducted on June 30, 2020 to identify what SO_2 control strategies are in place and what emission levels represent the BACT. BACT limits are emission rates and are determined on a case-by-case basis. The BACT emission rates are used in this report for comparison purposes only and do not represent an applicable standard. Eleven plants were listed in the RBLC database; all but one had add-on SO_2 control listed. The only facility with a coal boiler to not list SO_2 control, only an SO_2 limit, was Miller Brewing Company in Ohio. A summary of the RBLC entries for boilers firing coal is attached as Appendix B, the entries specific to SO_2 are in table B-1.

Of the FGD systems installed, 85% are wet systems and 12% are spray dryers. Wet scrubbers can achieve the highest removal efficiencies at greater than 90%, whereas dry scrubbers typically achieve less than 80% (USEPA Fact Sheet).

3.3 Cost Summary

The cost analysis for each of the boilers being reviewed is presented in the following sections.

3.3.1 Boiler #11 Cost Summary

SCR is the only NO_x reduction technology reviewed for cost since Boiler #11 already uses SNCR and the boiler design includes OFA. Low NO_x burners are not applicable to wood. The natural gas fired combustion stabilization burners are low NO_x but the combustion stabilizing burners are not part of this assessment. No other technology was found for application to this boiler system.

In order for an SCR to work on Boiler #11, the current ESP system would need to be replaced with a hot side ESP or, as an alternative, the air stream could be reheated to achieve sufficient temperature for the catalyst reaction. Catalysts require temperatures ranging from 480 degrees Fahrenheit (°F) to 800°F (ICAC, 1997). The exhaust temperature entering the existing ESP is at about 400 °F and would not be expected to change significantly upon the exit of the ESP.

As indicated earlier, SCR is typically applied to large coal and natural gas fired electrical utility boilers sized larger than what VDPU operates. The fact sheet does say SCR can be effective for large industrial boilers if the capacity factor is high enough. USEPA only refers to applying SCR technology to coal and natural gas fired boilers.

USEPA directly states that capital costs for SCR are significantly higher than other types of NOx controls due to the large volume of catalyst that is required. The cost of the catalyst is listed as $283/cubic foot (ft^3). In addition, retrofitting SCR to an existing unit can increase costs by over 30 percent (EPA/452/B-02-001, 2002, EPA Pollution Control Manual, Chapter 2 Section 4 NO_x Controls page 2-29).

> *"The increase in cost is primarily due to modifications to existing ductwork, the cost of structural steel and reactor construction, auxiliary equipment costs, such as additional fans, and engineering costs. In addition, significant demolition and relocation of equipment may be required to provide space for the reactor. These costs can account for over 30% of the capital costs associated with SCR"*

VDPU has space constraints which will make any construction difficult. The northern climate also impacts the available construction schedule.

Table 4 summarizes the cost of retrofitting Boiler #11 with an SCR NO control system. Costs are based on the USEPA "Air Pollution Control Technology Fact Sheet" for SCR, Table 1a Summary of Cost Information in $/MMBtu/hr (1999 Dollars) for Industrial Oil, Gas, and Wood boilers. The fact sheet is included as Appendix D.

Table 4: Boiler #11 SCR NO_x Control Cost Estimate Summary

Parameter	SCR
Capital Cost	$1,150,000
30% Retrofit Add-on[a]	$345,000
O&M Cost	$103,500
Annual Cost	$161,000
SCR Subtotal (1999 $)	$1,759,500
SCR Subtotal Adjusted for 2020 $[b]	$2,859,891
Pre-heater for exhaust[c]	Cost not available
Emission reduction (85% total which is 53.2% above the existing SNCR system at 31.8%)	53.2%
Emission reduction[d] (tpy)	42.07
Cost of emission reduction ($/ton)	$67,979+

a EPA/452/B-02-001 - EPA Air Pollution Control Cost Manual, Chapter 2 Section 4, page 2-29 states 30% for a retrofit factor. The Air Pollution Control Cost Estimation Spreadsheet for SCR, USEPA June 2019, states that the retrofit should be between 0.8 and 1.5 based on the level of difficulty. The USEPA spreadsheet states that a retrofit factor of 1 is for average difficulty. Based on the space constraints and limited construction season due to the climate at VDPU a cost percentage of 30 percent was used which is the same as a factor of 1.3.

b The inflation rate in the United States between 1999 and today is 62.54%, (U.S. Bureau of Labor Statistics), https://www.bls.gov/data/inflation_calculator.htm, June 2021.

c Preheater for exhaust in lieu of a hot side ESP. The cost for the preheater was not available but listed in the table in order to identify it as another cost with both capital and operating impacts.

d Emission reduction is based on 2016 emissions of 89.9 tons of NO_x which could be reduced by another 53.2% potentially by retrofitting Boiler #11 with SCR for NO_x reduction.

The cost to retro fit Boiler #11 with SCR would be $67,979 per ton of NO_x removed. That value does not include the cost to increase the heat of the ESP exhaust to a sufficient temperature for the catalyst. Since the dissolution of the Xcel Power Purchase Agreement for renewable power, the wood boiler has seen a reduction in use as evident in the summary of historical actual emissions. The trend of reduced operation for Boiler #11 is expected to continue.

3.3.2 Boiler #7 Cost Summary

SNCR

Table 5 summarizes the cost of retrofitting Boiler #7 with an SNCR NO_x control system. Costs are based on the USEPA "Air Pollution Control Technology Fact Sheet" for SNCR, EPA-452/F-03-031, page 2, a copy of which is in Appendix D. Information is in $/MMBtu/hr and $/megawatts (MW) (1999 Dollars). The excerpt from the fact sheet concerning SNCR costs for industrial boilers greater than 100 MMBtu/hr is presented below.

1. Capital Cost: 900 to 2,500 \$/MMBtu/hr (9,000 to 25,000 \$/MW)
2. Operation and Maintenance (O&M) Cost: 100 to 500 \$/MMBtu/hr (1,000 to 5,000 \$/MW)
3. Annualized Cost: 300 to 1,000 \$/MMBtu/hr (3,000 to 10,000 \$/MW)

EQUI 7 is 8.24 MW. SNCR is applicable to boilers operated full time as well as boilers only operated on a seasonal basis.

Table 5: Boiler #7 NO_x Control Cost Estimate Summary

Parameter	Boiler 7 (8.24 MW/175 MMBtu/hr)
Capital Cost (17,000 \$/MW)	\$140,080
O&M Cost (3,000 \$/MW)	\$24,720
Annual Cost (6,500 \$/MW)	\$53,560
SNCR Subtotal (1999 \$)	\$218,360
SNCR Subtotal Adjusted for 2020 \$ [a]	\$354,922
Emission Reduction Percent	40%
Emission Reduction [b] (tpy)	20.28
Cost of Emission Reduction [c] (\$/ton)	\$17,501

[a] *The inflation rate in the United States between 1999 and today is 62.54%, (U.S. Bureau of Labor Statistics, https://www.bls.gov/data/inflation_calculator.htm, June 2021.*

[b] *Emission reduction is based on a 4-year actual average of 2016–2019 emissions of 50.69 tons of NO_x from EQUI 7.*

[c] *Cost of emission reduction is rounded to the nearest whole dollar.*

The cost to retrofit Boiler #7 with SNCR would be about \$17,500 per ton of NO_x removed.

SCR

The costs for NO_x control are based on USEPA published information taken from the USEPA "Air Pollution Control Technology Fact Sheet" for SCR, EPA-452/F-03-032, a copy of which is in Appendix D. The cost information from the fact sheet is contained in table 1a – Summary of Cost Information in \$/MMBtu/hr (1999 Dollars). The table entry for Industrial Coal Boilers was used for Boiler #7. Where cost values have been provided as ranges, the average of the range has been used for estimating purposes. The control efficiency of SCR is based on an 85% capacity factor and annual control of NO_x. Table 6 summarizes the costs associated with retrofitting Boiler #7 with SCR for NO_x Control.

Table 6: Boiler #7 NO_x Control Cost Estimate Summary

Parameter	Boiler #7 (175 MMBtu/hr)
Capital Cost (12,500 $/MMBtu)	$2,187,500
30% Retrofit Add-on	$656,250
O&M Cost (300 $/MMBtu)	$52,500
Annual Cost (1,600 $/MMBtu)	$280,000
SCR Subtotal (1999 $)	$3,176,250
SCR Subtotal Adjusted for 2020 $ [a]	$5,162,677
Pre-heater for Exhaust	Cost Not Available [b]
Emission Reduction Percent	85%
Emission Reduction [c] (tpy)	43.09
Cost of Emission Reduction [d] ($/ton)	$117,601

[a] *The inflation rate in the United States between 1999 and today is 62.54%, (U.S. Bureau of Labor Statistics), https://www.bls.gov/data/inflation_calculator.htm, June 2021.*

[b] *Boiler #7 would require a preheater for exhaust in lieu of a hot side ESP. The cost for the preheater was not available but is listed in the table in order to identify it as another cost with both capital and operating impacts.*

[c] *Emission reduction is based on actual average emissions from 2016–2019 of 50.69 tons of NO_x from Boiler #7.*

[d] *Cost of emission reduction is rounded to the nearest whole dollar.*

The cost to retrofit Boiler #7 with SCR would be about $117,601 per ton of NO_x removed. That value does not include the cost to increase the heat of the ESP exhaust to a sufficient temperature for the catalyst.

USEPA directly states that capital costs for SCR are significantly higher than other types of NO_x controls due to the large volume of catalyst that is required. The cost of the catalyst is listed as $283/cubic foot. In addition, retrofitting SCR to an existing unit can increase costs by over 30% (USEPA 2002 EPA-452/F-03-032). The space constraints at VDPU would also add costs due to the requirement to relocate items and demolish structures in order to find the space for additional pollution control equipment. Construction in the colder climate also means the construction season is shorter which impacts schedules and costs.

Scrubbers

The costs for SO_2 control are based on USEPA published information taken from the USEPA “Air Pollution Control Technology Fact Sheet” EPA-452/F-03-034 for FGD, a copy of which is in Appendix D. The cost information from the fact sheet is contained in table 1b – Summary of Cost Information in $/kilowatts (kW) (2001 Dollars). The table entry for Industrial Coal Boilers was used for Boiler #7. Where cost values have been provided as ranges, the average of the range has been used for estimating purposes.

If a spray dryer technology is used a fabric filter will need to be added downstream of the scrubber to remove the sorbent that was injected in to the exhaust stream. The particulate collector is designed and operated as an integral part of the removal process as the solids continue to react with SO_2,

The level of SO_2 reductions are based on the actual annual emissions over the past 4 years. Because the facility is no longer producing electricity and district heating customers continue to decline, the operation of the boilers has trended downward. VDPU expects that the trend for decreased operation will become the normal operating mode going forward. The results of the cost estimating for both wet and spray dry technology are shown in Table 7.

Table 7: Boiler #7 SO_2 Control Cost Estimate Summary

Parameter	Boiler #7 (8.24 MW, 8,240 kW)	
	Wet	Spray Dry
Capital Cost (875 $/kW for wet and 675 $/KW for spray dry)	$7,210,000	$5,562,000
O&M Cost (14 $/kW for wet and 155 $/KW for spray dry)	$115,360	$1,277,200
Annual Cost (125 $/kW for wet and 275 $/KW for spray dry)	$1,030,000	$2,266,000
Subtotal (2001 $)	$8,355,360	$9,105,200
Subtotal Adjusted for 2020 $ [a]	$12,743,595	$13,887,251
Emission Reduction Percent	90%	80%
Emission Reduction [b] (tpy)	62.47	55.53
Cost of Emission Reduction ($/ton)	**$203,995**	**$250,086[d]**

Abbreviations: MW = megawatts; O&M = operation and maintenance

[a] *The inflation rate in the United States between 2001 and today is 52.52%, (U.S. Bureau of Labor Statistics), https://www.bls.gov/data/inflation_calculator.htm, June 2021.*

[b] *Emission reduction is based on a 4-year average of actual emissions reported from 2016–2019. Emissions of 69.41 tons of SO_2 are from Boiler #7.*

[c] *Cost of emission reduction is rounded to the nearest whole dollar.*

[d] *Cost of emission reduction does not include the addition of a fabric filter down stream of the spray dryer.*

Since the dissolution of the Xcel Power Purchase Agreement and the decline in steam customers, VDPU will be primarily a district heating facility and intends to use the smaller natural gas boilers being installed to satisfy most of the steam load.

3.4 Time to Implement Controls

To implement controls would involve the following steps and durations:

- Budgetary design and project approval (12 months),
- Detailed engineering design and bid documents (6-9 months),
- Bid solicitation, evaluation and selection (3-4 months),
- Procurement/contracting (3-4 months),
- Construction (6-10 months), and
- Commissioning (2-3 months).

This leads to an overall schedule of 32-42 months from concept to operation. The timeline for SNCR installation on Boiler #7 would be about half the amount of time as an SCR installation or scrubbers for SO_2. VDPU is a governmental institution that requires formal approval from a commission for any funding to occur.

3.5 Non-Air Quality Impacts

This section outlines in general terms the non-air quality related impacts that would result from add-on controls for Boiler #7 and Boiler #11. Tables 8 and 9 shows the impacts in general terms. For example, SCR uses a catalyst which are made from various ceramic materials such as titanium oxide or oxides of base metals (such as vanadium, molybdenum and tungsten), zeolites, or various precious metals. Mining to obtain catalyst materials has environmental implications

Table 8: Impacts of Potential Add-on Control Technologies

Technology	Boiler #7 SNCR or SCR	Boiler #11 SCR
Electrical Energy Consumption	Yes	Yes
Transportation Impacts	Yes	Yes
Solid Waste Generation	Yes	Yes
Increased Water Consumption	Yes	Yes

Table 9: Impacts of Potential SO_x Control Technologies

Technology	Boiler #7
Electrical Energy Consumption	Yes
Transportation Impacts	Yes
Solid Waste Generation	Yes
Increased Water Consumption	Yes

In addition, retrofitting boilers to support additional control technologies will result in greenhouse gas (GHG) emissions from, construction, truck traffic, material manufacturing, and electrical use. Assuming that the electricity to power the control systems is from some fossil fuel-fried generation, then the increased electrical demand would result in GHG emissions.

3.6 Remaining Useful Life

Boiler #11 began operating in 2006 and the expectation is that it will last about 25 years with proper maintenance. That means the remaining useful life of Boiler #11 is greater than 10 years. Boiler #7 was installed in 1955 and is due for a major overhaul. With additional maintenance, Boiler #7 is expected to last at least another 10 years.

4. SUMMARY

Review of available information suggests that the cost criteria for visibility improvement is less than that for BACT; however, the target values for economic feasibility are generally not published and are evaluated on a case-by-case basis. The USEPA Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State

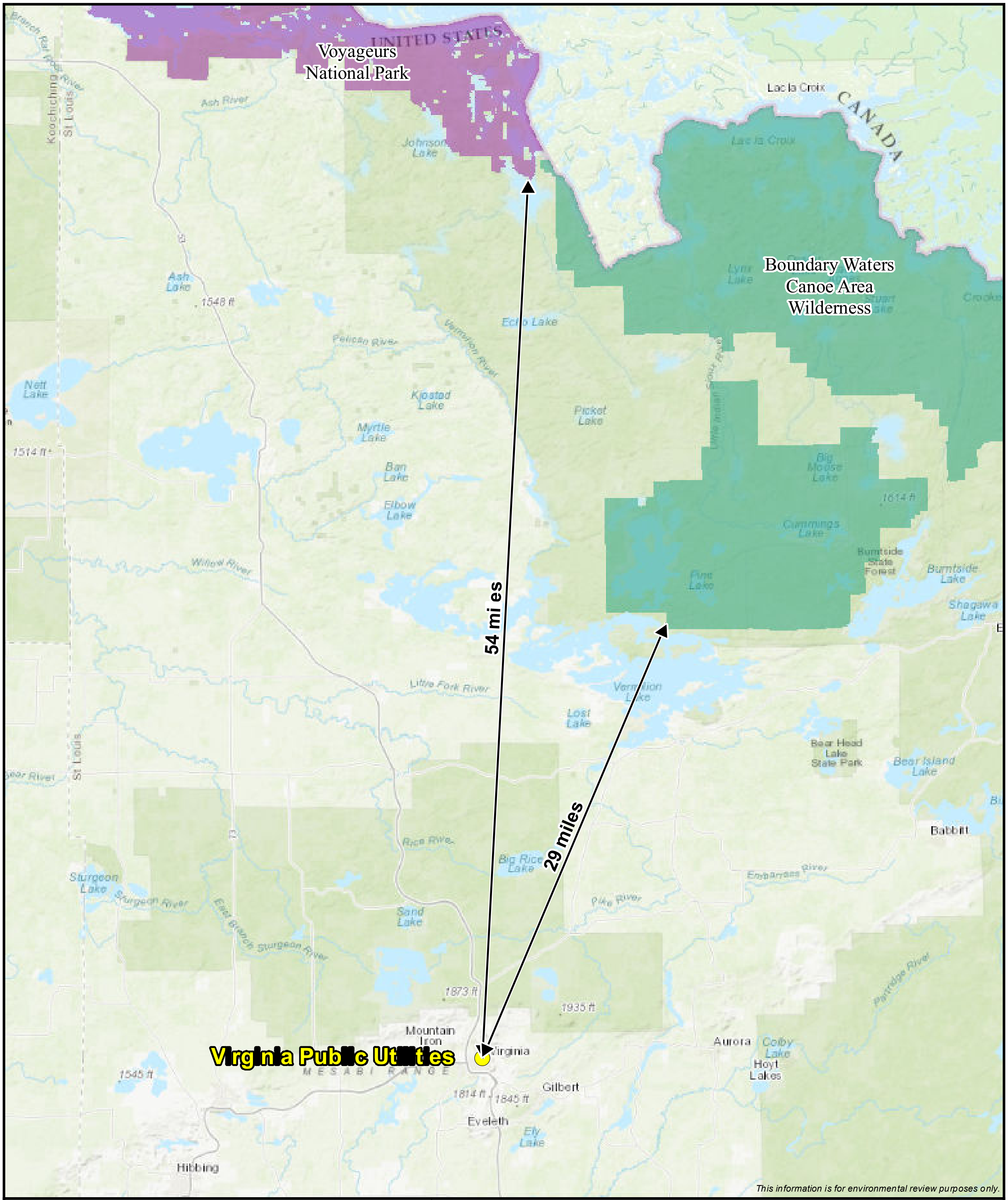
Implementation Plans for the Second Implementation Period (EPA-457/P-16-001, July 2016) provides guidance for states to establish control evaluation criteria, such as:

> "*…measures that cost less than $X/ton and that result in either (1) a visibility benefit greater than Y deciview at the most impacted Class I area or (2) cumulative visibility benefits across multiple affected Class I areas greater than Z deciview.*"

In the case of additionally controlling NO_x emissions from the Boiler #11 at VDPU, the only available technology would be to replace the SNCR system with SCR. The cost of a SCR system has been calculated to be to the SNCR is over $67,979 per ton of NO_x removal. This level of cost effectiveness would not be considered cost effective for BACT control, and should be considered cost-prohibitive for visibility protection.

Boiler #7 does not have any add on controls for either NO_x or SO_2. The lowest NO_x control cost would be for SNCR at $17,500 per ton of NO_x removed. The addition of SO_2 add on control would be $203,995 per ton of SO_2 removed for the least expensive option. This level cost effectiveness is above what is considered cost effective for BACT and should be considered cost prohibitive for visibility protection.

APPENDIX A SITE LOCATION MAP



● Virginia Public Utilities

🟩 Boundary Waters Canoe Area Wilderness

🟪 Voyageurs National Park

N

0 2.5 5 Miles

Virginia Department of Public Utilities
Site Location Map
Four Factor Analysis

ERM

M:\Clients\V-X\VPU\Virginia_ArcGIS\2020\03\Basemap\Site_Location_Map.mxd | REVISED: 06/02/2021 | SCALE: 1:525,000

DRAWN BY: JSS

APPENDIX B RACT/BACT/LAER SUMMARY

Appendix B-1

Reasonably Available Control Technology, Best Available Control Technology, Lowest Available Emission Rate Clearinghouse

RBLC Database Summary - EPA Database Accessed on June 30, 2020

Coal-Fired Boilers – SO_2

RBLC ID	Company	Boiler Size (MMBtu/hr)	Pollutant	Limit	Units	Technology	Basis For Limit	Permit Issuance Date	Process Type[1]
CA-1206	APMC Stockton Cogen Stockton Cogen Company	730	SO_2	59	lb/hr	Limestone injection with 70% minimum removal efficiency	BACT	9/16/2010	11.110
NE-0037	Cargill, Inc	1500	SO_2	0.11	lb/MMBtu	Limestone injection	BACT	9/8/2006	12.110
OH-0241	Miller Brewing Company	238	SO_2	1.6	lb/MMBtu		BACT	5/27/2004	12.110
VA-0267	VPI University VPI Power Station	146.7	SO_2	23.6	lb/hr	Dry scrubber flue gas desulfurization system, continuous emissions monitoring system (CEMS)	BACT	8/30/2001	12.110
NC-0092	International Paper Company Riegelwood Mill	249	SO_2	0.8	lb/MMBtu	Multiclone, variable throat venturi-type wet scrubber	BACT	5/10/2001	12.110
AZ-0055	Salt River Project Agricultural and Power District Navajo Generator Station	7725	SO_2	0		Flue gas desulfurization	BART	6/6/2012	11.110
MI-0400	Wolverine Power Supply Cooperative, Inc.	3030	SO_2	303	lb/hr	Dry flue gas desulfurization (spray dry absorber or polishing scrubber)	BACT	6/29/2011	11.110
TX-0595	Tenaska Trailblazer Partners, LLC	8307	SO_2	0.06	lb/MMBtu	Wet limestone scrubber	BACT	12/30/2010	11.110
MI-0399	Detroit Edison	7624	SO_2	0.107	lb/MMBtu	Wet flue gas desulfurization	BACT	12/21/2010	11.110
TX-0554	Coleto Creek	6670	SO_2	0.06	lb/MMBtu	Spray Dry Adsorber / Fabric Filter	BACT	5/3/2010	11.110
KY-0100	East Kentucky Power Cooperative, LLC J.K. Smith Generating Station	3000	SO_2	0.075	lb/MMBtu	Limestone Injection (circulating fluidized bed [CFB]) and flash dryer absorber with fresh lime injection	BACT	4/9/2010	11.110

EPA Website: https://cfpub.epa.gov/rblc/index.cfm?action=Search.BasicSearch&lang=en

[1] The process codes searched were 12.100 Industrial-size boilers/furnaces - Solid Fuel & Solid Fuel Mixes (> 100 MMBtu/hr to 250 MMBtu/hr) and 11.120 - Utility - and Large Industrial-Size Boilers/Furnaces (>250 MMBtu/hr) - Biomass (includes wood, wood waste, bagasse, and other biomass).

Notes:

The terms "RACT," "BACT," and "LAER" are acronyms for different program requirements under the NSR program.

RACT, or Reasonably Available Control Technology, is required on existing sources in areas that are not meeting national ambient air quality standards (i.e., non-attainment areas).

BACT, or Best Available Control Technology, is required on major new or modified sources in clean areas (i.e., attainment areas).

LAER, or Lowest Achievable Emission Rate, is required on major new or modified sources in non-attainment areas.

Appendix B-2

Reasonably Available Control Technology, Best Available Control Technology, Lowest Available Emission Rate Clearinghouse

RBLC Database Summary - EPA Database Accessed on June 30, 2020

Coal-Fired Boilers – NO_x

RBLC ID	Company	Boiler Size (MMBtu/hr)	Pollutant	Limit	Units	Technology	Basis For Limit	Permit Issuance Date	Process Type[1]
CA-1206	APMC Stockton Cogen Stockton Cogen Company	730	NO_x	50	ppm	Low bed temperature staged combustion, selective non-catalytic reduction (SNCR)	BACT	9/16/2010	11.110
NE-0037	Cargill, Inc	1500	NO_x	0.08	lb/MMBtu	Combustion control, SNCR	BACT	9/8/2006	12.110
ND-0020	Red Trail Energy, LLC Richardton Plant	250	NO_x	0.1	lb/MMBtu	SNCR	BACT	8/4/2004	12.110
OH-0241	Miller Brewing Company	238	NO_x	0.7	lb/MMBtu	Overfire air (OFA) and side fire air to reduce flame temperature	BACT	5/27/2004	12.110
NC-0092	International Paper Company Riegelwood Mill	249	NO_x	0.4	lb/MMBtu	Good combustion practices	BACT	5/10/2001	12.110
OK-0152	O G and E Muskogee Generating Station	1875.5	NO_x	0.15	lb/MMbtu	Low NO_x burners (LNB) and OFA	BART	1/30/2013	11.110
OK-0151	O G and E Muskogee Generating Station	1875.5	NO_x	0.15	lb/MMbtu	LNBs and OFA	BACT	1/17/2013	11.110
AZ-0055	Salt River Project Agricultural and Power District Navajo Generator Station	7725	NO_x	0.24	lb/MMBtu	LNBs and OFA	BACT	2/6/2012	11.110
MI-0400	Wolverine Power Supply Cooperative, Inc.	3030	NO_x	1	lb/MW-hr	SNCR	BACT	6/29/2011	11.110
TX-0595	Tenaska Trailblazer Partners, LLC	8307	NO_x	0.05	lb/MMBtu	selective catalytic reduction (SCR)	BACT	12/30/2010	11.110
MI-0399	Detroit Edison	7624	NO_x	0.08	lb/MMBtu	Staged combustion, LNBs, OFA, SCR	BACT	12/21/2010	11.110
TX-0554	Coleto Creek	6670	NO_x	0.06	lb/MMBtu	LNBs with OFA system, SCR	BACT	5/3/2010	11.110
KY-0100	East Kentucky Power Cooperative, LLC J.K. Smith Generating Station	3000	NO_x	0.07	lb/MMBtu	SNCR	BACT	4/9/2010	11.110
TX-0557	NRG Texas Power LLC Limestone Electric Generating Station	9061	NO_x	0.25	lb/MMBtu	Tuning of existing low NO_x firing system to induce deeper state combustion	BACT	2/1/2010	11.110
TX-0556	Southwestern Public Service Company Harrington Station Unit 1 Boiler	3630	NO_x	1452	lb/hr	Separated OFA windbox system; LNB tips and additional control to the burners	BACT	1/15/2010	11.110

EPA Website: https://cfpub.epa.gov/rblc/index.cfm?action=Search.BasicSearch&lang=en

[1] The process codes searched were 12.110 Industrial-size boilers/furnaces - Solid Fuel & Solid Fuel Mixes (> 100 MMBtu/hr to 250 MMBtu/hr) Coal (includes bituminous, subbituminous, anthracite, and lignite) and 11.110 - Utility - and Large Industrial-Size Boilers/Furnaces (>250 MMBtu/hr) - Coal (includes bituminous, subbituminous, anthracite, and lilgnite).

Notes:

The terms "RACT," "BACT," and "LAER" are acronyms for different program requirements under the NSR program.

RACT, or Reasonably Available Control Technology, is required on existing sources in areas that are not meeting national ambient air quality standards (i.e., non-attainment areas).

BACT, or Best Available Control Technology, is required on major new or modified sources in clean areas (i.e., attainment areas).

LAER, or Lowest Achievable Emission Rate, is required on major new or modified sources in non-attainment areas.

Appendix B-3

Reasonably Available Control Technology, Best Available Control Technology, Lowest Available Emission Rate Clearinghouse

RBLC Database Summary - EPA Database Accessed on June 30, 2020

Wood-Fired Boilers – NO_x

RBLC ID	Company	Boiler Size (MMBtu/hr)	Pollutant	Limit	Units	Technology	Basis For Limit	Permit Issuance Date	Process Type[1]
ME-0040	Robbins Lumber, Inc.	167.3	NO_x	25.1	lb/hr	Flue gas recirculation (FGR) / Selective non-catalytic reduction (SNCR)	BACT	6/30/2017	12.120
MI-0425	Arauco North America Grayling Particleboard	110	NO_x	95	lb/hr	Good combustion practices, low NO_x burners (LNB)	BACT	5/9/2017	12.120
MI-0421	Arauco North America Grayling Particleboard	110	NO_x	95	lb/hr	Good combustion practices, LNB	BACT	8/26/2016	12.120
SC-0149	Klausner Holding USA, Inc.	120	NO_x	0.14	lb/MMBtu	SNCR	Other	1/3/2013	12.120
FL-0332	Highlands Envirofuels (HEF), LLC Highlands Biorefinery and Cogeneration Plant	458.5	NO_x	0.1	lb/MMBtu	SNCR with urea or NH_3 injection, LNB	BACT	9/23/2011	12.120
FL-0322	Southeast Renewable Fuels (SRF), LLC Sweet Sorghum-to-Ethanol Advanced Biorefinery	536	NO_x	0.1	lb/MMBtu	Good combustion practices, SNCR, selective catalytic reduction (SCR), or combination with urea or NH_3 injection	BACT	12/23/2010	12.120
AR-0161	Sun Bio Material Company	1,200	NO_x	0.06	lb/MMBtu	SCR	BACT	9/23/2019	11.120
FL-0359	US Sugar Corporation	1,077	NO_x	0.1	lb/MMBtu	SNCR (NH_3 injection)	BACT	11/29/2016	11.120
KS-0034	Abengoa Bioenergy Biomass of Kansas (ABBK)	500	NO_x	0.3	lb/MMBtu	SCR and overfire air (OFA) system	BACT	5/27/2014	11.120
CA-1225	Sierra Pacific Industries	468	NO_x	0.13	lb/MMBtu	SNCR	BACT	4/25/2014	11.120
VT-0039	North Springfield Sustainable Energy Project, LLC	464	NO_x	0.03	lb/MMBtu	Bubbling fluidized bed boiler design and SCR	BACT	4/19/2013	11.120
GA-0141	Ogethorpe Power Corporation Warren County Biomass Energy Facility	341	NO_x	0.1	lb/MMBtu	SNCR	BACT	12/17/2010	11.120
VT-0037	Beaver Wood Energy Fair Haven, LLC	482	NO_x	0.03	lb/MMBtu	Good combustion control and SCR	BACT	2/10/2012	11.120
ME-0037	Verso Bucksport, LLC	817	NO_x	0.15	lb/MMBtu	SNCR	BACT	11/29/2010	11.120
CA-1203	Sierra Pacific Industries	335.7	NO_x	80	ppm	SNCR	BACT	8/30/2010	11.120
NH-0018	Berlin Station, LLC Burgess Biopower	1,013	NO_x	0.06	lb/MMBtu	SCR with NH_3 injection[2]	LAER	7/26/2010	11.120
CT-0156	NRG Energy	600	NO_x	0.06	lb/MMBtu	Regenerative SCR	LAER	4/6/2010	11.120
AL-0250	Boise White Paper, LLC	435	NO_x	0.3	lb/MMBtu	LNB	BACT	3/23/2010	11.120
TX-0553	Lindale Renewable Energy, LLC	1,256	NO_x	0.15	lb/MMBtu	SNCR	BACT	1/8/2010	11.120

EPA Website: https://cfpub.epa.gov/rblc/index.cfm?action=Search.BasicSearch&lang=en

[1] The process codes searched were 12.100 Industrial-size boilers/furnaces - Solid Fuel & Solid Fuel Mixes (> 100 MMBtu/hr to 250 MMBtu/hr) and 11.120 - Utility - and Large Industrial-Size Boilers/Furnaces (>250 MMBtu/hr) - Biomass (includes wood, wood waste, bagasse, and other biomass).

[2] This entry is the only facility listed in the RBLC database under the process categories searched, that has been confirmed to have been built and is using an SCR for NO_x control.

Notes:

The terms "RACT," "BACT," and "LAER" are acronyms for different program requirements under the NSR program.

RACT, or Reasonably Available Control Technology, is required on existing sources in areas that are not meeting national ambient air quality standards (i.e., non-attainment areas).

BACT, or Best Available Control Technology, is required on major new or modified sources in clean areas (i.e., attainment areas).

LAER, or Lowest Achievable Emission Rate, is required on major new or modified sources in non-attainment areas.

APPENDIX C EXCERPTS FROM FOSTER WHEELER OPERATORS MANUAL (BOILER #11)

The grate is fed onto the grate by means of two pneumatic fuel distributors situated on the furnace front wall. These are located above the grate and are evenly spaced across the width of the boiler. Each distributor receives litter from a metering feeder and blows it into the furnace using a variable pressure air stream.

The feeders are set up using a pulse air, rotating damper to regulate the front to back fuel trajectory onto the grate. Conveying air used by the feeders is supplied by a separate distributor air fan.

l) Fuel Feeders

The boiler is equipped with two variable speed twin screw feeders that are used to regulate fuel feed to each pneumatic distributor. These are located above and in close proximity to each fuel distributor.

Biomass fuel is metered into the boiler at a controlled rate set by load demand.
The feeders are supplied with integral fuel bins that receive biomass from the plant conveyor.

m) Primary Air System (HTUsee Air & Flue Gas System DescriptionUTH)

A single variable speed motor driven FD fan provides combustion air to the grate. The fan is furnished with an inlet filter, venturi metering section and inlet silencer. Airflow control is split ranged using variable speed with inlet damper control at low load. The output of the fan is regulated from load demand from the combustion control system.

Air discharged from the fan is heated in the undergrate air heater prior to entering the undergrate air plenums.

n) Secondary Air System (TUsee Air & Flue Gas System DescriptionUTH)

A single variable speed motor driven FD fan provides combustion air to the overfire air nozzles above the grate. The fan is furnished with an inlet duct, venturi metering section, intake silencer and inlet control damper. Airflow control is split ranged using variable speed with inlet damper control at low load. The output of the fan is regulated from load demand from the combustion control system.

Discharge air is heated and directed to a series of overfire air nozzles on the front and rear furnace walls.

o) Distributor Air Fan

A single, constant speed distributor air fan is furnished to supply ambient air to the fuel distributors. The fan is set up to supply a constant amount of air and is unregulated by the operator.

General

The following description should be read in conjunction with drawing No. 113925V-0202 Air & Flue Gas P&ID.

Note:

FWL terminal points are designated as “TP FWL”.

Combustion Air System

Air for combustion is supplied from two separate sources, undergrate air and overfire air. Each system is sized to deliver approximately 60% and 40% respectively of the required total combustion air. It is necessary that both systems be in operation to operate the boiler when firing biomass fuel.

Undergrate air

The undergrate air system provides combustion air to the under the grate air zones. A forced draft fan delivers ambient air to the grate taken from inside the building via an intake duct. The incoming air stream to the fan is metered through a venturi section 11FE-510, equipped with flow transmitter 11FT 510 (by others) and flow switch 11FSH 510 (by others). An intake silencer 11EDS 511 is furnished for noise attenuation downstream of the metering venturi.

An inlet louver damper 11EJM 511is furnished for low load control of airflow. This is driven by air operated actuator 11FY 510 in response to a 4-20mA control signal from the DCS combustion controls. The actuator is provided with open/closed limit switches 11ZSL510/ZSH 510 for proof of closed and purge positions.

The variable speed undergrate air fan is driven by an electric motor, 11MV 510 equipped with winding temperature thermostats. The fan is also equipped with bearing temperature monitors 11TE 510A/B.

The FD fan is equipped with a variable speed drive for discharge capacity control that is spilt ranged for operation with the inlet louver control damper. Fan speed is controlled from the characterized 4-20mA combustion control signal.

Pressure at the FD fan discharge is monitored by pressure transmitter 11PT 510 prior to being directed through a tubular air heater 11ESE 510 that is utilised to preheat the undergrate air. This is necessary with all high moisture fuels for optimum combustion conditions. The temperature of air leaving the air heater is unregulated and varies with load. Temperature is measured by transmitter 11TT 512.

The grate is divided into three separate air zones from front to back. These, in turn are subdivided into LH and RH sections for a total of six independent zones. Air to each zone can be biased by individual manual inlet dampers. Control of these dampers allows the

operator to manually bias the air split, front to back and side to side for optimum burning and emissions control.

Thermocouples 11TE 721A/B/C & 11TE 722 A/B/C are provided on the underside of the grate for temperature monitoring and alarm purposes.

Overfire Air

The overfire air system provides combustion air to a series of fixed nozzles that penetrate the furnace front and rear walls. There are three elevations of nozzles on the front wall and four elevations on the rear wall (see DSCo. Manual for details). These are optimized during commissioning and set up to inject air above the grate into a zone where suspension burning takes place. Different nozzle elevations are selected in order to provide optimum combustion conditions with minimum emissions.

Secondary air is drawn from inside the boiler building through an intake duct. The duct is equipped with a venturi section 11FE 515 and transmitter 11FT 515 (by others) for flow metering purposes. A silencer 11EDS 510 is provided on the fan intake for noise attenuation purposes.

An inlet louver damper 11EJM 510 is furnished for low load control of airflow. This is driven by air operated actuator 11FY 515 in response to a 4-20mA control signal from the DCS combustion controls. The actuator is provided with open/closed limit switches 11ZSL 515/ZSH 515 for proof of closed and purge positions.

The overfire air fan is driven by a variable speed electric motor 11MV 515 equipped with winding temperature thermostats. The motor is also equipped with bearing temperature detectors TE-A-09-006A/006B.

The fan is equipped with inboard and outboard bearing temperature detectors 11TE 515A/B.

The overfire air fan is equipped with a variable speed drive for discharge capacity control that is spilt ranged for operation with the inlet louver control damper. Fan speed is controlled from the characterized 4-20mA combustion control signal.

Pressure at the overfire air fan discharge is monitored by pressure transmitter 11PT 515 prior to being directed through a tubular air heater 11ESE 511 that is utilised to preheat the overfire air. The temperature of air leaving the air heater is unregulated and varies with load. Temperature is measured by transmitter 11TT 517.

Preheated air is routed through a series of ducts to the front and rear overfire air nozzles into the furnace. Isolation dampers are provided on the nozzles for operational flexibility since some nozzles, or complete nozzle elevations may not be used during normal operation.

APPENDIX D USEPA AIR CONTROL TECHNOLOGY FACT SHEETS

EPA-452/F-03-031

Air Pollution Control Technology
Fact Sheet

Name of Technology: Selective Non -Catalytic Reduction (SNCR)

Type of Technology: Control Device - Chemical reduction of a pollutant via a reducing agent.

Applicable Pollutants: Nitrogen Oxides (NO_X)

Achievable Emission Limits/Reductions:

NO_X reduction levels range from 30% to 50% (EPA, 2002). For SNCR applied in conjunction with combustion controls, such as low NO_X burners, reductions of 65% to 75% can be achieved (ICAC 2000).

Applicable Source Type: Point

Typical Industrial Applications:

There are hundreds of commercially installed SNCR systems on a wide range of boiler configurations including: dry bottom wall fired and tangentially fired units, wet bottom units, stokers, and fluidized bed units. These units fire a variety of fuels such as coal, oil, gas, biomass, and waste. Other applications include thermal incinerators, municipal and hazardous solid waste combustion units, cement kilns, process heaters, and glass furnaces.

Emission Stream Characteristics:

a. **Combustion Unit Size:** In the United States, SNCR has been applied to boilers and other combustion units ranging in size from 50 to 6,000 MMBtu/hr (5 to 600MW/hr) (EPA, 2002). Until recently, it was difficult to get high levels of NOx reduction on units greater than 3,000 MMBtu (300 MW) due to limitations in mixing. Improvements in SNCR injection and control systems have resulted in high NO_X reductions (> 60%) on utility boilers greater than 6,000 MMBtu/hr (600MW). (ICAC, 2000).

b. **Temperature:** The NO_X reduction reaction occurs at temperatures between 1600°F to 2100°F (870°C to 1150°C) (EPA, 2002). Proprietary chemicals, referred to as enhancers or additives, can be added to the reagent to lower the temperature range at which the NO_X reduction reactions occur.

c. **Pollutant Loading:** SNCR tends to be less effective at lower levels of uncontrolled NO_X. Typical uncontrolled NO_X levels vary from 200 ppm to 400 ppm (NESCAUM, 2000). SNCR is better suited for applications with high levels of PM in the waste gas stream than SCR.

d. **Other Considerations:** Ammonia slip refers to emissions of unreacted ammonia that result from incomplete reaction of the NO_X and the reagent. Ammonia slip may cause: 1) formation of ammonium sulfates, which can plug or corrode downstream components, 2) ammonia absorption into fly ash, which may affect disposal or reuse of the ash, and 3) increased plume visibility. In the U.S., permitted ammonia slip levels are typically 2 to 10 ppm (EPA, 2002). Ammonia slip at these levels do not result in plume formation or pose human health hazards. Process optimization after installation can lower slip levels.

Nitrous Oxide (N_2O) is a by-product formed during SNCR. Urea based reduction generates more N_2O than ammonia-based systems. At most, 10% of the NO_X reduced in urea-based SNCR is converted to N_2O. Nitrous oxide does not contribute to ground level ozone or acid formation. (ICAC,2000)

Emission Stream Pretreatment Requirements: None

Cost Information: All costs are in year 1999 dollars. (NESCAUM, 2000; ICAC, 2000; and EPA, 2002)

The difficulty of SNCR retrofit on existing large coal-fired boilers is considered to be minimal. However, the difficulty significantly increases for smaller boilers and packaged units. The primary concern is adequate wall space within the boiler for installation of injectors. Movement and/or removal of existing watertubes and asbestos from the boiler housing may be required. In addition, adequate space adjacent to the boiler must be available for distribution system equipment and for performing maintenance. This may require modifications to ductwork and other boiler equipment.

A typical breakdown of annual costs for industrial boilers will be 15% to 35% for capital recovery and 65% to-85% for operating expense (ICAC,2000). Since SNCR is an operating expense-driven technology, its cost varies directly with NO_X reduction requirements and reagent usage. Optimization of the injection system after start up can reduce reagent usage and, subsequently, operating costs. Recent improvements in SNCR injection systems have also lowered operating costs.

There is a wide range of cost effectiveness for SNCR due to the different boiler configurations and site-specific conditions, even within a given industry. Cost effectiveness is impacted primarily by uncontrolled NO_X level, required emissions reduction, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty. The cost effectiveness of SNCR is less sensitive to capacity factor than SCR. Control of NO_X is often only required during the ozone season, typically June through August. Since SNCR costs are a function of operating costs, SNCR is an effective control option for seasonal NO_X reductions.

Costs are presented below for industrial boilers greater than 100 MMBtu/hr.

a. **Capital Cost:** 900 to 2,500 $/MMBtu/hr (9,000 to 25,000 $/MW)

b. **O&M Cost:** 100 to 500 $/MMBtu/hr (1,000 to 5,000 $/MW)

c. **Annualized Cost:** 300 to 1000 $/MMBtu/hr (3,000 to 10,000 $/MW)

d. **Cost per Ton of Pollutant Removed:**

Annual Control: 400 to 2,500 $/ton of NO_X removed
Seasonal Control: 2,000 to 3,000 $/ton of NO_X removed

Theory of Operation:

SNCR is based on the chemical reduction of the NO_X molecule into molecular nitrogen (N_2) and water vapor (H_2O). A nitrogen based reducing agent (reagent), such as ammonia or urea, is injected into the post combustion flue gas. The reduction reaction with NO_X is favored over other chemical reaction processes at temperatures ranging between 1600°F and 2100°F (870°C to 1150°C), therefore, it is considered a selective chemical process (EPA, 2002).

Both ammonia and urea are used as reagents. Urea-based systems have advantages over ammonia based systems. Urea is non-toxic, less volatile liquid that can be stored and handled more safely. Urea solution droplets can penetrate farther into the flue gas when injected into the boiler, enhancing the mixing with the flue gas which is difficult in large boilers. However, urea is more expensive than ammonia. The Normalized Stoichiometric Ratio (NSR) defines the ratio of reagent to NO_X required to achieve the targeted NO_X reduction. In practice, more than the theoretical amount of reagent needs to be injected into the boiler flue gas to obtain a specific level of NO_X reduction.

In the SNCR process, the combustion unit acts as the reactor chamber. The reagent is generally injected within the boiler superheater and reheater radiant and convective regions, where the combustion gas temperature is at the required temperature range. The injection system is designed to promote mixing of the reagent with the flue gas. The number and location of injection points is determined by the temperature profiles and flow patterns within the combustion unit.

Certain application are more suited for SNCR due to the combustion unit design. Units with furnace exit temperatures of 1550°F to 1950°F (840°C to 1065°C), residence times of greater than one second, and high levels of uncontrolled NO_X are good candidates.

During low-load operation, the location of the optimum temperature region shifts upstream within the boiler. Additional injection points are required to accommodate operations at low loads. Enhancers can be added to the reagent to lower the temperature range at which the NO_X reduction reaction occurs. The use of enhancers reduces the need for additional injection locations.

Advantages:

- Capital and operating costs are among the lowest of all NO_X reduction methods.
- Retrofit of SNCR is relatively simple and requires little downtime for large and medium size units.
- Cost effective for seasonal or variable load applications.
- Waste gas streams with high levels of PM are acceptable.
- Can be applied with combustion controls to provide higher NO_X reductions.

Disadvantages:

- The waste gas stream must be within a specified temperature range.
- Not applicable to sources with low NO_X concentrations such as gas turbines.
- Lower NO_X reductions than Selective Catalytic Reduction (SCR).
- May require downstream equipment cleaning.
- Results in ammonia in the waste gas stream which may impact plume visibility, and resale or disposal of ash.

References:

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EPA-452/F-03-032

Air Pollution Control Technology
Fact Sheet

Name of Technology: Selective Catalytic Reduction (SCR)

Type of Technology: Control Device - Chemical reduction via a reducing agent and a catalyst.

Applicable Pollutants: Nitrogen Oxides (NOx)

Achievable Emission Limits/Reductions: SCR is capable of NOx reduction efficiencies in the range of 70% to 90% (ICAC, 2000). Higher reductions are possible but generally are not cost-effective.

Applicable Source Type: Point

Typical Industrial Applications: Stationary fossil fuel combustion units such as electrical utility boilers, industrial boilers, process heaters, gas turbines, and reciprocating internal combustion engines. In addition, SCR has been applied to nitric acid plants. (ICAC, 1997)

Emission Stream Characteristics:

a. **Combustion Unit Size:** In the United States, SCR has been applied to coal- and natural gas-fired electrical utility boilers ranging in size from 250 to 8,000 MMBtu/hr (25 to 800 MW) (EPA, 2002). SCR can be cost effective for large industrial boilers and process heaters operating at high to moderate capacity factors (>100 MMBtu/hr or >10MW for coal-fired and >50 MMBtu/hr or >5MW for gas-fired boilers). SCR is a widely used technology for large gas turbines.

b. **Temperature:** The NOx reduction reaction is effective only within a given temperature range. The optimum temperature range depends on the type of catalyst used and the flue gas composition. Optimum temperatures vary from 480°F to 800°F (250°C to 427°C) (ICAC, 1997). Typical SCR systems tolerate temperature fluctuations of ± 200°F (± 90°C) (EPA, 2002).

c. **Pollutant Loading:** SCR can achieve high reduction efficiencies (>70%) on NOx concentrations as low as 20 parts per million (ppm). Higher NOx levels result in increased performance; however, above 150 ppm, the reaction rate does not increase significantly (Environex, 2000). High levels of sulfur and particulate matter (PM) in the waste gas stream will increase the cost of SCR.

d. **Other Considerations:** Ammonia slip refers to emissions of unreacted ammonia that result from incomplete reaction of the NOx and the reagent. Ammonia slip may cause: 1) formation of ammonium sulfates, which can plug or corrode downstream components, and 2) ammonia absorption into fly ash, which may affect disposal or reuse of the ash. In the U.S., permitted ammonia slip levels are typically 2 to 10 ppm. Ammonia slip at this levels do not result in plume formation or human health hazards. Process optimization after installation can lower slip levels.

   Waste gas streams with high levels of PM may require a sootblower. Sootblowers are installed in the SCR reactor to reduce deposition of particulate onto the catalyst. It also reduces fouling of downstream equipment by ammonium sulfates.

The pressure of the waste gas decreases significantly as it flows across the catalyst. Application of SCR generally requires installation a new or upgraded induced draft fan to recover pressure.

Emission Stream Pretreatment Requirements: The flue gas may require heating to raise the temperature to the optimum range for the reduction reaction. Sulfur and PM may be removed from the waste gas stream to reduce catalyst deactivation and fouling of downstream equipment.

Cost Information:

Capital costs are significantly higher than other types of NOx controls due to the large volume of catalyst that is required. The cost of catalyst is approximately 10,000 $\$/m^3$ (283 $\$/ft^3$). A 350 MMBtu/hr natural gas-fired boiler operating at 85% capacity requires approximately 17 m^3 (600 ft^3). For the same sized coal-fired boiler, the required catalyst is on the order of 42 m^3 (1,500 ft^3). (NESCAUM 2000).

SCR is a proprietary technology and designs on large combustion units are site specific. Retrofit of SCR on an existing unit can increase costs by over 30% (EPA, 2002). The increase in cost is primarily due to ductwork modification, the cost of structural steel, and reactor construction. Significant demolition and relocation of equipment may be required to provide space for the reactor.

The O&M costs of using SCR are driven by the reagent usage, catalyst replacement, and increased electrical power usage. SCR applications on large units (>100 MMBtu/hr) generally require 20,000 to 100,000 gallons of reagent per week (EPA, 2002). The catalyst operating life is on the order of 25,000 hours for coal-fired units and 40,000 hours for oil- and gas-fired units (EPA, 2002). A catalyst management plan can be developed so that only a fraction of the total catalyst inventory, rather than the entire volume, is replaced at any one time. This distributes the catalyst replacement and disposal costs more evenly over the lifetime of the system. O&M costs are greatly impacted by the capacity factor of the unit and annual versus seasonal control of NO_X.

O&M cost and the cost per ton of pollutant removed is greatly impacted by the capacity factor and whether SCR is utilized seasonally or year round.

Table 1a: Summary of Cost Information in $/MMBtu/hr (1999 Dollars) [a, b]

Unit Type	Capital Cost ($/MMBtu)	O&M Cost [d] ($/MMBtu)	Annual Cost [d] ($/MMBtu)	Cost per Ton of Pollutant Removed ($/ton)
Industrial Coal Boiler	10,000 - 15,000	300	1,600	2,000 - 5,000
Industrial Oil, Gas, Wood [c]	4,000 - 6,000	450	700	1,000 - 3,000
Large Gas Turbine	5,000 - 7,500	3,500	8,500	3,000 - 6,000
Small Gas Turbine	17,000 - 35,000	1,500	3,000	2,000 - 10,000

Table 1b: Summary of Cost Information in $/MW (1999 Dollars) [a, b]

Unit Type	Capital Cost ($/MW)	O&M Cost [d] ($/MW)	Annual Cost [d] ($/MW)	Cost per Ton of Pollutant Removed ($/ton)
Industrial Coal Boiler	1,000 - 1,500	30	160	2,000 - 5,000
Industrial Oil, Gas, Wood [c]	400 - 600	45	70	1,000 - 3,000
Large Gas Turbine	500 - 750	350	850	3,000 - 6,000
Small Gas Turbine	1,700- 3,500	150	300	2,000 - 10,000

[a] (ICAC, 1997; NESCAUM, 2000; EPA, 2002)
[b] Assumes 85% capacity factor and annual control of NOx
[c] SCR installed on wood fired boiler assumes a hot side electrostatic precipitator for PM removal
[d] Coal and oil O&M and annual costs are based on 350MMBtu boiler, and gas turbine O&M and annual costs are based on 75 MW and 5 MW turbine

Theory of Operation:

The SCR process chemically reduces the NOx molecule into molecular nitrogen and water vapor. A nitrogen based reagent such as ammonia or urea is injected into the ductwork, downstream of the combustion unit. The waste gas mixes with the reagent and enters a reactor module containing catalyst. The hot flue gas and reagent diffuse through the catalyst. The reagent reacts selectively with the NOx within a specific temperature range and in the presence of the catalyst and oxygen.

Temperature, the amount of reducing agent, injection grid design and catalyst activity are the main factors that determine the actual removal efficiency. The use of a catalyst results in two primary advantages of the SCR process over the SNCR: higher NOx control efficiency and reactions within a lower and broader temperature range. The benefits are accompanied by a significant increase in capital and operating costs. The catalyst is composed of active metals or ceramics with a highly porous structure. Catalysts configurations are generally ceramic honeycomb and pleated metal plate (monolith) designs. The catalyst composition, type, and physical properties affect performance, reliability, catalyst quantity required, and cost. The SCR system supplier and catalyst supplier generally guarantee the catalyst life and performance. Newer catalyst designs increase catalyst activity, surface area per unit volume, and the temperature range for the reduction reaction.

Catalyst activity is a measure of the NOx reduction reaction rate. Catalyst activity is a function of many variables including catalyst composition and structure, diffusion rates, mass transfer rates, gas temperature, and gas composition. Catalyst deactivation is caused by:

- poisoning of active sites by flue gas constituents,
- thermal sintering of active sites due to high temperatures within reactor,
- blinding/plugging/fouling of active sites by ammonia-sulfur salts and particulate matter, and
- erosion due to high gas velocities.

As the catalyst activity decreases, NOx removal decreases and ammonia slip increases. When the ammonia slip reaches the maximum design or permitted level, new catalyst must be installed. There are several different locations downstream of the combustion unit where SCR systems can be installed. Most coal-fired applications locate the reactor downstream of the economizer and upstream of the air heater and particulate control devices (hot-side). The flue gas in this location is usually within the optimum temperature window for NOx reduction reactions using metal oxide catalysts. SCR may be applied after PM and sulfur removal

equipment (cold-side), however, reheating of the flue gas may be required, which significantly increases the operational costs.

SCR is very cost-effective for natural gas fired units. Less catalyst is required since the waste gas stream has lower levels of NOx, sulfur, and PM. Combined-cycle natural gas turbines frequently use SCR technology for NOx reduction. A typical combined-cycle SCR design places the reactor chamber after the superheater within a cavity of the heat recovery steam generator system (HRSG). The flue gas temperature in this area is within the operating range for base metal-type catalysts.

SCR can be used separately or in combination with other NOx combustion control technologies such as low NOx burners (LNB) and natural gas reburn (NGR). SCR can be designed to provide NOx reductions year-round or only during ozone season.

Advantages:

- Higher NOx reductions than low-NOx burners and Selective Non-Catalytic Reduction (SNCR)
- Applicable to sources with low NOx concentrations
- Reactions occur within a lower and broader temperature range than SNCR.
- Does not require modifications to the combustion unit

Disadvantages:

- Significantly higher capital and operating costs than low-NOx burners and SNCR
- Retrofit of SCR on industrial boilers is difficult and costly
- Large volume of reagent and catalyst required.
- May require downstream equipment cleaning.
- Results in ammonia in the waste gas stream which may impact plume visibility, and resale or disposal of ash.

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EPA-452/F-03-034

Air Pollution Control Technology Fact Sheet

Name of Technology: Flue Gas Desulfurization (FGD) - Wet, Spray Dry, and Dry Scrubbers

Type of Technology: Control Device - absorption and reaction using an alkaline reagent to produce a solid compound.

Applicable Pollutants: Sulfur dioxide (SO_2)

Achievable Emission Limits/Reductions: Scrubbers are capable of reduction efficiencies in the range of 50% to 98%. The highest removal efficiencies are achieved by wet scrubbers, greater than 90% and the lowest by dry scrubbers, typically less than 80%. Newer dry scrubber designs are capable of higher control efficiencies, on the order of 90%.

Applicable Source Type: Point

Typical Industrial Applications: Stationary coal- and oil-fired combustion units such as utility and industrial boilers, as well as other industrial combustion units such as municipal and medical waste incinerators, cement and lime kilns, metal smelters, petroleum refineries, glass furnaces, and H_2SO_4 manufacturing facilities. Approximately 85% of the FGD systems installed in the US are wet systems, 12% are spray dry and 3% are dry systems.

Emission Stream Characteristics:

a. **Combustion Unit Size:** SO_2 scrubbers have been applied combustion units firing coal and oil ranging in size from 5 MW to over 1,500 MW (50 MMBtu/hr to 15,000 MMBut/hr). Dry and spray scrubbers are generally applied to units less than 3,000 MMBtu/hr (300 MW) (EPA, 2000).

b. **Temperature:** For wet scrubbers, typical inlet gas temperatures are 150°C to 370°C (300°F to 700°F) (FETC, 1996). For spray dry systems, the temperature of the flue gas exiting the absorber must be 10°C to 15°C (20°F to 30°F) above the adiabatic saturation temperature. Optimal temperatures for SO_2 removal for dry sorbent injection systems range from 150°C to 180°C (300°F to 350°F). Optimal temperatures for SO_2 removal when applying dry sorbent injection systems vary between 150°C to 1000°C (300°F to 1830°F) depending on the sorbent properties (Joseph, 1998)

c. **Pollutant Loading:** SO_2 scrubbers are limited to dilute SO_2 waste gas streams of approximately 2000 ppm.(Cooper, 2002).

d. **Other Considerations:** The amount of chlorine in the flue gas affects the amount of water evaporated by the system due to the formation of salts. Chlorine content improves the SO_2 removal but also results in salt deposition on the absorber and downstream equipment (Schnelle, 2002).
An additional or upgraded induced draft (ID) fan may be required to compensate for flue gas pressure drop across the absorber.

Many wet systems reheat the flue gas downstream of the absorber to prevent corrosion caused by condensation inside the ducts and stack and reduce plume visibility.

Emission Stream Pretreatment Requirements: In spray dry and dry injection systems, the flue gas must be cooled to a temperature range of 10°C to 15°C (20°F to 30°F) above adiabatic saturation. This temperature range avoids wet solids deposition on downstream equipment and plugging of the baghouse. A heat recovery boiler, an evaporative cooler or a heat exchanger is typically used to cool the gas.

Cost Information:

Capital costs for SO_2 scrubbers have decreased by over 30% since the beginning of the 1990's. Current costs for SO_2 scrubbers applied to electric utilities are reported to be approximately $100/kW (Smith, 2001). Retrofit of scrubbers on existing units can increase the capital cost up to 30%. Retrofit costs vary significantly between sites and depend on space limitations, major modifications to existing equipment (e.g., ductwork and stack) and the operating condition of the units (e.g., temperature, flowrate).

O&M costs increase with increasing sulfur content since more reagent is required to treat the same volume of gas. Typical reagents such as lime and limestone are inexpensive; however, the use of proprietary reagents or reagent enhancers or additives that can significantly increase the O&M cost. Limestone is generally available for 10 to 20 $/ton and lime is available for 60 to 80 $/ton (Smith, 2001). Waste product disposal costs vary from $10/ton to $30/ton and byproduct saleable prices vary from 0 to 15 $/ton (Smith, 2001). The addition of a scrubbers causes a loss of energy available for generating steam due to evaporation of water and the energy required to drive the reaction. New scrubber designs result in an energy penalty of less than 1% of the total plant energy (Srivastava, 2001).

Table 1a: Summary of Cost Information in $/MMBtu/hr (2001 Dollars) [a]

Scrubber Type	Unit Size (MMBtu/hr)	Capital Cost ($/MMBtu)	O&M Cost [b] ($/MMBtu)	Annual Cost ($/MMBtu)	Cost per Ton of Pollutant Removed ($/ton)
Wet	> 4,000	10,000 -25,000	200 - 800	25 - 40	200 - 500
	< 4,000	25,000 - 150,000	800 - 1,800	60 - 600	500 - 5,000
Spray Dry	> 2,000	4,000 - 15,000	600 - 1,000		150 - 300
	< 2,000	30,000 - 150,000	1,000 - 30,000	10,000 - 50,000	500 - 4,000

Table 1b: Summary of Cost Information in $/MW (2001 Dollars) [a]

Scrubber Type	Unit Size (MW)	Capital Cost ($/kW)	O&M Cost [b] ($/kW)	Annual Cost ($/kW)	Cost per Ton of Pollutant Removed ($/ton)
Wet	> 400	100 - 250	2 - 8	20 - 50	200 - 500
	< 400	250 - 1,500	8 - 20	50 - 200	500 - 5,000
Spray Dry	> 200	40 - 150	4 - 10	20 -50	150 - 300
	< 200	150 - 1,500	10 - 300	50 - 500	500 - 4,000

[a] (EIA, 2002; EPA, 2000; Srivastava, 2001)

[b] Assumes capacity factor > 80%

Theory of Operation:

The FDG or SO_2 scrubbing process typically uses a calcium or sodium based alkaline reagent. The reagent is injected in the flue gas in a spray tower or directly into the duct. The SO_2 is absorbed, neutralized and/or oxidized by the alkaline reagent into a solid compound, either calcium or sodium sulfate. The solid is removed from the waste gas stream using downstream equipment.

Scrubbers are classified as "once-through" or "regenerable", based on how the solids generated by the process are handled. Once-through systems either dispose of the spent sorbent as a waste or utilize it as a byproduct. Regenerable systems recycle the sorbent back into the system. At the present time, regenerable processes have higher costs than once-through processes; however, regenerable processes might be chosen if space or disposal options are limited and markets for byproducts (gypsum) are available (Cooper, 2002). In 1998, approximately 3% of FDG systems installed in the US were regenerable.

Both types of systems, once-through and regenerable, can be further categorized as wet, dry, or semi-dry. Each of these processes is described in the following sections.

Wet Systems

In a wet scrubber system, flue gas is ducted to a spray tower where an aqueous slurry of sorbent is injected into the flue gas. To provide good contact between the waste gas and sorbent, the nozzles and injection locations are designed to optimize the size and density of slurry droplets formed by the system. A portion of the water in the slurry is evaporated and the waste gas stream becomes saturated with water vapor. Sulfur dioxide dissolves into the slurry droplets where it reacts with the alkaline particulates. The slurry falls to the bottom of the absorber where it is collected. Treated flue gas passes through a mist eliminator before exiting the absorber which removes any entrained slurry droplets. The absorber effluent is sent to a reaction tank where the SO_2-alkali reaction is completed forming a neutral salt. In a regenerable system, the spent slurry is recycled back to the absorber. Once through systems dewater the spent slurry for disposal or use as a by-product.

Typical sorbent material is limestone, or lime. Limestone is very inexpensive but control efficiencies for limestone systems are limited to approximately 90%. Lime is easier to manage on-site and has control efficiencies up to 95% but is significantly more costly (Cooper 2002). Proprietary sorbents with reactivity-enhancing additives provide control efficiencies greater than 95% but are very costly. Electrical utilities store large volumes of limestone or lime on site and prepare the sorbent for injection, but this is generally not cost effective for smaller industrial applications.

The volume ratio of reagent slurry to waste gas is referred to as the liquid to gas ratio (L/G). The L/G ratio determines the amount of reagent available for reaction with SO_2. Higher L/G ratios result in higher control efficiencies. Higher L/G also increases oxidation of the SO_2, which results in a decrease of the formation of scale in the absorber. O&M costs are a direct function of reagent usage, so increasing the L/G increases annual costs. L/G ratios are approximately 1:1 for wet scrubbers and are expressed as gallons of slurry per 1000 ft^3 of flue gas (liters of slurry/1000Nm^3 of flue gas).

Oxidation of the slurry sorbent causes gypsum (calcium sulfate) scale to form in the absorber. Limestone forced oxidation (LSFO) is a newer process based on wet limestone scrubbing which reduces scale. In LSFO, air is added to the reaction tank which oxidizes the spent slurry to gypsum. The gypsum is removed from the reaction tank prior to the slurry being recycled to the absorber. The recycle slurry has a lower concentration of gypsum and scale formation in the absorber is significantly reduced. Gypsum can be commercially sold, eliminating the need for landfilling of the waste product (Srivastava, 2001). In addition to scale control, the larger size gypsum crystals formed in LSFO settle and dewater more efficiently, reducing the size of the byproduct handling equipment (EPA, 2002). However, LSFO requires additional blowers which increase the capital and annual costs of the system.

Wet limestone scrubbing has high capital and operating cost due to the handling of liquid reagent and waste. Nonetheless, it is the preferred process for coal-fired electric utility power plants burning coal due to the low cost of limestone and SO_2 control efficiencies from 90% up to 98% (Schnelle, 2002).

Semi-Dry Systems

Semi-dry systems, or spray dryers, inject an aqueous sorbent slurry similar to a wet system, however, the slurry has a higher sorbent concentration. As the hot flue gas mixes with the slurry solution, water from the slurry is evaporated. The water that remains on the solid sorbent enhances the reaction with SO_2. The process forms a dry waste product which is collected with a standard particulate matter (PM) collection device such as a baghouse or ESP. The waste product can be disposed, sold as a byproduct or recycled to the slurry.

Various calcium and sodium based reagents can be utilized as sorbent. Spray dry scrubbers typically inject lime since it is more reactive than limestone and less expensive than sodium based reagents. The reagent slurry is injected through rotary atomizers or dual-fluid nozzles to create a finer droplet spray than wet scrubber systems (Srivastava, 2000).

The performance of a lime spray dry scrubber is more sensitive to operating conditions. A “close approach” to adiabatic saturation temperature is required to maximize the removal of SO_2. However, excess moisture causes the wet solids to deposit on the absorber and downstream equipment. The optimum temperature is 10°C to 15°C (20°F to 50°F) below saturation temperature (Srivastava, 2000). Lower L/G ratios, approximately 1:3, must be utilized do to the limitation on flue gas moisture (Schnelle, 2002). Flue gas with high SO_2 concentrations or temperatures reduce the performance of the scrubber (Schnelle, 2002).

SO_2 control efficiencies for spray dry scrubbers are slightly lower than wet systems, between 80% and 90% due to its lower reactivity and L/G ratios. Application of a single spray dry absorber is limited to combustion units less than 200 MW (2,000 MMBtu/hr) (IEA, 2001). Larger combustion units require multiple absorber systems. The capital and operating cost for spray dry scrubbers are lower than for wet scrubbing because equipment for handling wet waste products is not required. In addition, carbon steel can be used to manufacture the absorber since the flue gas is less humid. Typically applications include electric utility units burning low- to medium- sulfur coal, industrial boilers, and municipal waste incinerators that require 80% SO_2 control efficiency (Schnelle, 2002).

Dry systems

Dry sorbent injection systems, pneumatically inject powdered sorbent directly into the furnace, the economizer, or downstream ductwork. The dry waste product is removed using particulate control equipment such as a baghouse or electrostatic precipitator (ESP). The flue gas is generally cooled prior to the entering the PM control device. Water can be injected upstream of the absorber to enhance SO_2 removal (Srivastava, 2001).

Furnace injection requires flue gas temperatures between 950°C to 1000°C (1740°F to 1830°F) in order to decompose the sorbent into porous solids with high surface area (Srivastava 2001). Injection into the economizer requires temperatures of 500°C to 570°C (930°F to 1060°F) (Srivastava 2001). Duct injection requires the dispersion of a fine sorbent spray into the flue gas downstream of the air preheater. The injection must occur at flue gas temperatures between 150°C to 180°C (300°F to 350°F) (Joseph, 1998).

Dry sorbent systems typically use calcium and sodium based alkaline reagents. A number of proprietary reagents are also available. A typical injection system uses several injection lances protruding from the furnace or duct walls. Injection of water downstream of the sorbent injection increases SO_2 removal by the sorbent.

An even distribution of sorbent across the reactor and adequate residence time at the proper temperature are critical for high SO_2 removal rates (Srivastava 2001). Flue gas must be kept 10°C to 15°C (20°F to 50°F) below saturation temperature to minimize deposits on the absorber and downstream equipment.

Dry scrubbers have significantly lower capital and annual costs than wet systems because they are simpler, demand less water and waste disposal is less complex. Dry injection systems install easily and use less space, therefore, they are good candidates retrofit applications. SO_2 removal efficiencies are significantly lower than wet systems, between 50% and 60% for calcium based sorbents. Sodium based dry sorbent injection into the duct can achieve up to 80% control efficiencies (Srivastava 2001). Dry sorbent injection is viewed as an emerging SO_2 control technology for medium to small industrial boiler applications. Newer applications of dry sorbent injection on small coal-fired industrial boilers have achieved greater than 90% SO_2 control efficiencies.

Advantages:

- High SO_2 removal efficiencies, from 50% up to 98%.
- Products of reaction may be reusable
- Difficulty of retrofit is moderate to low
- Inexpensive and readily available reagents

Disadvantages:

- High capital and O&M costs
- Scaling and deposit of wet solids on absorber and downstream equipment
- Wet systems generate a wet waste product and may result in a visible plume
- Cannot be used for waste gas SO_2 concentrations greater than 2,000 ppm
- Disposal of waste products significantly increases O&M costs

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Memo

To	Hassan Bouchareb, Minnesota Pollution Control Agency
From	Ann Curnow, ERM and Jeff Minter Virginia Public Utilities
Date	6 April 2022
Reference	Regional Haze NOx Reduction – Four Factor Analysis Follow-up Boiler 7 Virginia Public Utilities – Permit No. 13700028-102
Subject	Decommissioning Schedule for Coal-Fired Boiler #7 (EQUI 2)

Dear Mr. Bouchareb,

This memorandum is to inform the Minnesota Pollution Control Agency (MPCA) that the Virginia Public Utilities (VPU) currently plans to decommission Boiler #7 by January 1, 2025. Due to a reduction of steam customers, the regular operation of Boiler #7 is no longer feasible. VPU will be operating natural gas package boilers to supply the district steam requirements instead of relying on the large utility boilers. The main advantage of the smaller natural gas boilers is that they can operate at lower steam production rates.

VPU will operate Boiler #7 at a reduced capacity until January 1, 2025. If Boiler #7 is decommissioned as currently planned, the backup boilers will be Boiler #10 (EQUI 4) followed by Boiler #11 (EQUI 16). These boilers will operate on natural gas.

Boiler #7 actual NO_x emissions from 2016 to 2019 averaged 63.21 tons per year. The calculated potential emissions of NO_x from Boiler #7 is 396.78 tons per year. Decommissioning Boiler #7 will also result in reduction of sulfur dioxide, mercury, and greenhouse gas emissions.

Ann Curnow

(612) 347-7112

MINNESOTA POLLUTION
CONTROL AGENCY

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January 29, 2020

Richard Rosvold, Environmental Compliance Manager
Xcel Energy - Allen S King Generating Plant
1103 King Plant Road
Bayport, MN 55003

RE: Request for Information - Regional Haze Rule, Reasonable Progress, Four Factor Analysis

Dear Mr. Rosvold:

The Minnesota Pollution Control Agency (MPCA) is currently preparing information for the second planning period (Round 2) comprehensive update to Minnesota's Regional Haze State Implementation Plan (SIP) as required by the Regional Haze Rule (40 CFR § 51.308). States are responsible for developing a Regional Haze SIP that addresses regional haze in each Class I area located within the state and in each Class I area located outside the state which may be affected by emissions from sources within the state. The Regional Haze SIP is required to identify existing facilities that cause or contribute to visibility impairment; analyze, identify, and apply federally-enforceable control strategies for those sources; and periodically demonstrate reasonable progress toward reaching visibility goals. States are also responsible for periodic comprehensive updates to their Regional Haze SIP that address these same topics. Minnesota's Round 2 Regional Haze SIP must be submitted to the U.S. Environmental Protection Agency (U.S. EPA) by July 31, 2021.

Minnesota has two Class I areas within its borders, the Boundary Waters Canoe Area Wilderness (BWCA) and Voyageurs National Park (Voyageurs). Other nearby Class I areas include Isle Royale National Park in Michigan. Therefore, Minnesota must prepare a Regional Haze SIP that identifies sources that cause or contribute to visibility impairment in these areas. To meet the core requirements for regional haze for these areas, Minnesota must submit a SIP that contains the plan elements and supporting documentation for all required analyses identified in 40 CFR § 51.308(f).

In the first planning period (Round 1), the focus of the Regional Haze Rule was on establishing Best Available Retrofit Technology (BART) for certain older sources and reasonable progress towards national visibility goals. In Round 2, there are no BART requirements; therefore, the focus is on making reasonable progress. The U.S. Environmental Protection agency has defined the methodology that states must use to determine what measures are necessary to make reasonable progress in 40 CFR § 51.308(f)(2). At minimum, the reasonable progress analysis must use the four factors identified in 40 CFR § 51.308(f)(2)(i) to evaluate and determine the emission reduction measures necessary to make reasonable progress. The four factors are:

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

Data from the IMPROVE monitoring sites at BWCA and Voyageurs indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X).

You are receiving this letter because your facility was identified as a significant source of NO_X and SO_2 and is located close enough to the BWCA or Voyageurs to potentially cause or contribute to visibility impairment in these Class I areas. Therefore, the MPCA requests that you prepare a "Four Factor Analysis" for the following emission units:

1. Boiler 1 (EQUI 68 / EU 001) that addresses emissions of NO_X and SO_2

The analysis should be prepared using the U.S. Environmental Protection Agency guidance[1] that provides recommendations for how each of the factors should be determined.

Preparation of the comprehensive update to Minnesota's Regional Haze SIP will require extensive planning and review of sources in Minnesota. The MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to prepare the Regional Haze SIP. The MPCA expects air quality modeling of potential regional emissions reductions will be conducted beginning in spring 2020. I appreciate your attention to this matter and request that you **submit the Four Factor Analysis by July 31, 2020**.

If you have any questions regarding this matter, or would like to request a meeting to further discuss the contents of this letter, please contact me by phone at 651-757-2653 or by email at Hassan.Bouchareb@state.mn.us.

Sincerely,

Hassan Bouchareb

This document has been electronically signed.

Hassan M. Bouchareb
Engineer
Environmental Analysis and Outcomes Division

Cc: Patricia Leaf, Xcel Energy
Deepa de Alwis, MPCA
Cory Boeck, MPCA
Frank Kohlasch, MPCA
Agency Interest ID 2346

Address questions and submittals requested above to:

Hassan M. Bouchareb
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155-4194
(651) 757-2653
Hassan.Bouchareb@state.mn.us

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[1] **U.S. Environmental Protection Agency.** *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 20, 2019, https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

MINNESOTA POLLUTION CONTROL AGENCY

520 Lafayette Road North | St. Paul, Minnesota 55155-4194 | 651-296-6300
800-657-3864 | Use your preferred relay service | info.pca@state.mn.us | Equal Opportunity Employer

January 29, 2020

Richard Rosvold, Environmental Compliance Manager
Xcel Energy - Sherburne County Generating Plant
13999 Industrial Boulevard
Becker, MN 55308

RE: Request for Information - Regional Haze Rule, Reasonable Progress, Four Factor Analysis

Dear Mr. Rosvold:

The Minnesota Pollution Control Agency (MPCA) is currently preparing information for the second planning period (Round 2) comprehensive update to Minnesota's Regional Haze State Implementation Plan (SIP) as required by the Regional Haze Rule (40 CFR § 51.308). States are responsible for developing a Regional Haze SIP that addresses regional haze in each Class I area located within the state and in each Class I area located outside the state which may be affected by emissions from sources within the state. The Regional Haze SIP is required to identify existing facilities that cause or contribute to visibility impairment; analyze, identify, and apply federally-enforceable control strategies for those sources; and periodically demonstrate reasonable progress toward reaching visibility goals. States are also responsible for periodic comprehensive updates to their Regional Haze SIP that address these same topics. Minnesota's Round 2 Regional Haze SIP must be submitted to the U.S. Environmental Protection Agency (U.S. EPA) by July 31, 2021.

Minnesota has two Class I areas within its borders, the Boundary Waters Canoe Area Wilderness (BWCA) and Voyageurs National Park (Voyageurs). Other nearby Class I areas include Isle Royale National Park in Michigan. Therefore, Minnesota must prepare a Regional Haze SIP that identifies sources that cause or contribute to visibility impairment in these areas. To meet the core requirements for regional haze for these areas, Minnesota must submit a SIP that contains the plan elements and supporting documentation for all required analyses identified in 40 CFR § 51.308(f).

In the first planning period (Round 1), the focus of the Regional Haze Rule was on establishing Best Available Retrofit Technology (BART) for certain older sources and reasonable progress towards national visibility goals. In Round 2, there are no BART requirements; therefore, the focus is on making reasonable progress. The U.S. Environmental Protection agency has defined the methodology that states must use to determine what measures are necessary to make reasonable progress in 40 CFR § 51.308(f)(2). At minimum, the reasonable progress analysis must use the four factors identified in 40 CFR § 51.308(f)(2)(i) to evaluate and determine the emission reduction measures necessary to make reasonable progress. The four factors are:

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

Data from the IMPROVE monitoring sites at BWCA and Voyageurs indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X).

You are receiving this letter because your facility was identified as a significant source of NO_X and SO_2 and is located close enough to the BWCA or Voyageurs to potentially cause or contribute to visibility impairment in these Class I areas. Therefore, the MPCA requests that you prepare a “Four Factor Analysis” for the following emission units:

1. Tangential - Fired Coal Burner 1 (EQUI 72 / EU 001) that addresses emissions of NO_X and SO_2
2. Tangential - Fired Coal Burner 2 (EQUI 74 / EU 002) that addresses emissions of NO_X and SO_2
3. Opposed - Fired Coal Burner 3 (EQUI 73 / EU 003) that addresses emissions of NO_X and SO_2

The analysis should be prepared using the U.S. Environmental Protection Agency guidance[1] that provides recommendations for how each of the factors should be determined.

Preparation of the comprehensive update to Minnesota’s Regional Haze SIP will require extensive planning and review of sources in Minnesota. The MPCA is working with the Lake Michigan Air Directors Consortium (LADCO) to prepare the Regional Haze SIP. The MPCA expects air quality modeling of potential regional emissions reductions will be conducted beginning in spring 2020. I appreciate your attention to this matter and request that you **submit the Four Factor Analysis by July 31, 2020**.

If you have any questions regarding this matter, or would like to request a meeting to further discuss the contents of this letter, please contact me by phone at 651-757-2653 or by email at Hassan.Bouchareb@state.mn.us.

Sincerely,

Hassan Bouchareb

This document has been electronically signed.

Hassan M. Bouchareb
Engineer
Environmental Analysis and Outcomes Division

Cc: Patricia Leaf, Xcel Energy
Deepa de Alwis, MPCA
Cory Boeck, MPCA
Frank Kohlasch, MPCA
Agency Interest ID 2344

Address questions and submittals requested above to:

Hassan M. Bouchareb
Minnesota Pollution Control Agency
520 Lafayette Road North
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[1] **U.S. Environmental Protection Agency.** *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 20, 2019, https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

414 Nicollet Mall
Minneapolis, MN 55401

July 29, 2020 *sent via e-mail*

Hassan M. Bouchareb
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155

RE: Request for Information- Regional Haze Rule, Reasonable Progress
Xcel Energy-Allen S. King Generating Plant

Dear Mr. Bouchareb,

This letter is in response to your request for information (RFI) addressed to me dated January 29, 2020. This letter requested a "Four Factor Analysis" (Analysis) for Xcel Energy's Allen S. King Plant Unit 1 (EQUI 68) to assist in the development of Minnesota's Regional Haze State Implementation Plan (SIP). On February 10, 2020, Xcel Energy spoke with you about this RFI and the need for an Analysis given the planned retirement of this unit effectively reducing emissions from these unit to zero by the end of 2028. You indicated that if the retirement dates were made enforceable that an Analysis would not be necessary. This response provides an update on our efforts to secure an enforceable retirement date for Allen S. King Plant Unit 1.

Xcel Energy continues to lead the clean energy transition with a plan that will reduce our carbon emissions in the Upper Midwest 80% by 2030 and help us achieve our vision of 100% carbon-free electricity by 2050. The key to this transition of reducing carbon while keeping bills affordable is retiring our coal fired units by 2030. As we operate the coal fired units until their retirement, we will not only continue to reduce carbon emissions, but also emissions of sulfur dioxide and oxides of nitrogen, through seasonal dispatch (idling units in spring and fall months when demand is low and renewable energy is high).

Xcel Energy proposed to retire Allen S. King Plant Unit 1 by December 31, 2028 to the Minnesota Public Utility Commission (MPUC). A key part of this retirement process is to gain MPUC approval to do so. The mechanism for gaining this approval is the Integrated Resource Plan (IRP) Filing process with the MPUC. Xcel Energy continues to work with the MPUC to gain approval of our IRP filing. At this time the MPUC has not yet approved the IRP filing and, as a result, we are not able to commit to an enforceable retirement date for this unit. Once the MPUC has approved the retirement plans for Allen S. King Unit 1, Xcel Energy commits to incorporating the retirement date into the air permit if the permit is open at that time or to filing for an Administrative Order with the MPCA which will commit the unit to a retirement date of no later than December 31, 2028. The MPUC is expected to issue a final order on the Xcel Energy IRP filing by mid-2021.

Please notify me if the MPCA requires a retirement commitment earlier than this anticipated final order date.

If you have additional questions, please contact either me (612.269.9015 or richard.a.rosvold@xcelenergy.com) or Patti Leaf from my staff (612.964.1176 or patricia.b.leaf@xcelenergy.com).

Richard A. Rosvold

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Richard A. Rosvold
Date: 2020.07.27 16:25:16
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Richard A. Rosvold
Director Environmental Services

CC: Deepa de Alwis, MPCA
Cory Boeck, MPCA
Kari Palmer, MPCA
Brian Behm
Randy Capra
Patrick Flowers
Patricia Leaf

Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

July 29, 2020 *sent via e-mail*

Hassan M. Bouchareb
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155

RE: Request for Information- Regional Haze Rule, Reasonable Progress
Xcel Energy- Sherburne County Generating Plant

Dear Mr. Bouchareb,

This letter is in response to your request for information (RFI) to me dated January 29, 2020. That letter requested a "Four Factor Analysis" (Analysis) for Xcel Energy's Sherburne County Generating Units 1, 2 and 3 (EQUI72, EQUI74 and EQUI73) to assist in the development of Minnesota's Regional Haze State Implementation Plan (SIP). On February 10, 2020, Xcel Energy spoke with you about this RFI and the need for an Analysis given the planned retirement of these units effectively reducing emissions from these units to zero by 2030. You indicated that if the retirement dates were made enforceable that an Analysis would not be necessary. This response provides an update on our efforts to secure enforceable retirement dates for Sherburne County Generating Units 1, 2 and 3.

Xcel Energy continues to lead the clean energy transition with a plan that will reduce our carbon emissions in the Upper Midwest 80% by 2030 and help us achieve our vision of 100% carbon-free electricity by 2050. The key to this transition of reducing carbon while keeping bills affordable is retiring our coal fired units by 2030. As we operate the coal fired units until their retirement, we will not only continue to reduce carbon emissions, but also emissions of sulfur dioxide (SO_2) and oxides of nitrogen (NO_x), through seasonal dispatch (idling units in spring and fall months when demand is low and renewable energy is high).

Xcel Energy proposed and has received approval from the Minnesota Public Utility Commission (MPUC) through the Integrated Resource Plan (IRP) Filing to retire Sherburne County Generating Unit 2 by December 31, 2023 and Unit 1 by December 31, 2026. Xcel Energy has worked with Joe Carlson, MPCA, to incorporate the retirement dates for Sherco Units 1 and 2 into the Xcel Energy-Sherburne County Generating Plant Air Permit 14100004-101. The permit is currently going through the renewal process and is on public notice as of 7/14/2020. The retirement dates have been incorporated into the permit:

Sherco Unit 1: December 31, 2026 (Permit Condition 5.57.1)
Sherco Unit 2: December 31, 2023 (Permit Condition 5.58.1)

Xcel Energy has also proposed to the MPUC through the IRP Filing to retire Sherburne County Unit 3 by December 31, 2030 but has not yet received MPUC approval. Xcel Energy continues to work with the MPUC to gain approval of our IRP filing. In that the MPUC has not yet approved the IRP filing, we are not yet able to commit to an enforceable retirement date for this unit. Once the MPUC has approved the retirement plan for Sherburne County Unit 3, Xcel Energy commits to incorporating the retirement date into the air permit if the permit is open at that time or to enter into an Administrative Order (AO) with the MPCA which will commit the unit to a retirement date of no later than December 31, 2030, or complete some other action with the MPCA to secure an enforceable retirement date to support the MPCA's Regional Haze SIP. As the Agency is aware, this unit is co-owned by Xcel Energy and Southern Minnesota Municipal Power Agency (SMMPA). SMMPA, as co-owner, is also willing to commit to an enforceable retirement date for Unit 3, subject to approval by its regulatory body. The MPUC is expected to issue a final order on the Xcel Energy IRP filing mid-2021. Considering the planned retirement of Unit 3 by December 31, 2030 there will be only 2 years of useful life remaining and any investments in the unit would bear a high compliance cost.

For reference, Unit 3 has already reduced emissions to support Minnesota's regional haze goals. In 2016, as part of the Reasonably Attributable Visibility Impairment (RAVI) Settlement for the Sherco Plant, Xcel Energy accepted an SO_2 limit for Unit 3 of 0.29 pounds SO_2/Million Btu (MBtu), on a 30-day rolling average effective June 1, 2017 even though it was not part of the original RAVI discussion. For context, the Unit 3 average 30-day rolling SO_2 emission rate from the effective date through June 30, 2020 is 0.22 pounds SO_2/MBtu, well below the permitted SO_2 emission rate limit. Outside the RAVI settlement, Unit 3 has a NO_x emission rate permit limit of 0.50 pounds NO_x/MBtu, on a 30-day rolling average. The actual emission rate runs well below this limit. Average emissions based on the same time period outlined above for SO_2 emissions are 0.12 pounds NO_x/MBtu, approximately 25% of the units permitted NO_x limit.

As requested, it has been verified that emissions of sulfur dioxide and oxides of nitrogen for Unit 3 are projected to be significantly lower in 2028, 2029 and 2030 than they were in 2016.

Please notify me if the MPCA requires a retirement commitment earlier than this anticipated final order date.

If you have additional questions, please contact either me (612.269.9015 or richard.a.rosvold@xcelenergy.com) or Patti Leaf from my staff (612.964.1176 or patricia.b.leaf@xcelenergy.com).

Richard A. Rosvold
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Richard A. Rosvold
Director Environmental Services

CC: Deepa de Alwis, MPCA
Cory Boeck, MPCA
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