

Appendix B

Re-Calculating CALPOST Visibility Outputs with the New IMPROVE Algorithm

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**Instructions:
A Postprocessor for Recalculating CALPOST Visibility Outputs
with the New IMPROVE Algorithm**

**Version 2
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Introduction

CALPOST can be used to process outputs from CALPUFF modeling of a source's emissions to calculate the 24-hr average visibility impairments caused by primary and secondary particulate matter attributable to emissions from the modeled source. Those increments are presented in two tables, both labeled "Ranked Daily Visibility Change", in the CALPOST output (.LST) file. The table of interest to us has the subtitle "Modeled Extinction by Species" and lists the dates and locations of such incremental impacts in light extinction (b_{ext}) in ranked order, starting with the one that represents the largest percentage change in light extinction.¹

In addition, with a different setup of the control file CALPOST.INP, the CALPOST postprocessor can be used to calculate 24-hr averages of NO_x concentrations. As described below, the outputs from that additional CALPOST run can be used to assess the visibility impact of the NO_2 gas in the source plume.

Visibility effects due to particulate matter are calculated in CALPOST from CALPUFF-modeled particulate matter component concentrations using effectively the "traditional" IMPROVE algorithm. CALPOST allows for choice of the humidity scattering enhancement function ($f(RH)$) to be used with the IMPROVE algorithm; for modeling in connection with the US EPA's Regional Haze Regulations (RHR), the appropriate form of $f(RH)$ is the one described and tabulated in the EPA's 2003 guidance for tracking progress under the RHR. Visibility effects due to NO_2 are not considered in the CALPOST visibility calculation.

Recently, the IMPROVE Steering Committee developed a new algorithm for estimating light extinction from particulate matter component concentrations. This algorithm (the "new IMPROVE algorithm") provides a better correspondence between the measured visibility and

¹ The other table in the CALPOST visibility output file, with the subtitle "% of Modeled Extinction by Species", provides equivalent results in terms of changes in the haze index, in deciviews. The two tables represent the same results, with identical ranking of events, while just using different (but mathematically related) metrics.

that calculated from particulate matter component concentrations. The new algorithm differs in several substantive ways from the traditional one:

- The extinction efficiencies of sulfates, nitrates, and organics have been changed and are now functions of their concentrations. The extinction efficiencies of sulfate and nitrate are no longer identical, although the new hygroscopic scattering enhancement factors applied to them are the same.
- The concentration of particulate organic matter (POM; variously also labeled OCM or OMC, and sometimes just called “organics”) is now taken to be 1.8 times that of the measured organic carbon (OC) concentration. (Confusingly, CALPOST labels the organics concentration as OC.)
- The contribution of fine sea salt to light extinction has been added, and is accompanied by its own hygroscopic scattering enhancement factor, $f_{ss}(RH)$.
- The light scattering by air itself (Rayleigh scattering) now varies with site elevation and mean temperature. It is to be rounded off to the nearest one Mm^{-1} when used with the new algorithm.
- The light absorption by NO_2 gas has been added.

The new IMPROVE algorithm is represented by the following formula:²

$$\begin{aligned}
 b_{ext} = & 2.2 \cdot f_s(RH) \cdot [small\ sulfate] + 4.8 \cdot f_l(RH) \cdot [large\ sulfate] \\
 & + 2.4 \cdot f_s(RH) \cdot [small\ nitrate] + 5.1 \cdot f_l(RH) \cdot [large\ nitrate] \\
 & + 2.8 \cdot [small\ organics] + 6.1 \cdot [large\ organics] \\
 & + 10 \cdot [elemental\ carbon] \\
 & + 1 \cdot [fine\ soil] \\
 & + 1.7 \cdot f_{ss}(RH) \cdot [sea\ salt] \\
 & + 0.6 \cdot [coarse\ matter] \\
 & + Rayleigh\ scattering\ (site\ specific) \\
 & + 0.33 \cdot [NO_2(ppb)]
 \end{aligned}
 \tag{Eq. 1}$$

The concentrations of “large” and “small” sulfate particles are calculated as follows:

$$\begin{aligned}
 [large\ sulfate] &= ([total\ sulfate]/20) \cdot [total\ sulfate] \text{ if } [total\ sulfate] < 20\ \mu g^3 \\
 [large\ sulfate] &= [total\ sulfate] \text{ if } [total\ sulfate] \geq 20\ \mu g/m^3 \\
 [small\ sulfate] &= [total\ sulfate] - [large\ sulfate].
 \end{aligned}
 \tag{Eqs. 2}$$

Identical formulas, with changes in component names, are used for nitrate and organics. In effect, these formulas conclude that low concentrations of these components are mainly in the form of “small” particles with their own extinction efficiency and $f_s(RH)$, while high

² Square brackets denote concentrations.

concentrations (approaching $20 \mu\text{g}/\text{m}^3$) are mainly in the form of “large” particles with a different extinction efficiency and $f_L(\text{RH})$. The scaling factor $[\text{total sulfate}]/20$ sets the fraction of total sulfate that is small.

The sea salt concentration is taken to be $1.8 \cdot [\text{Cl}^-]$ or, if chloride ion measurements are not available, the chlorine concentration can be used in its place. Site specific Rayleigh scattering values have been calculated for all IMPROVE sites.³ Nitrogen dioxide concentrations are not measured at IMPROVE sites, but the ambient NO_2 concentrations under natural conditions can be expected to be negligibly small. The higher NO_2 concentration in a source plume may be great enough to cause a change in visibility, however.

In order to enable CALPOST to calculate CALPUFF-modeled source impacts on visibility using the new IMPROVE algorithm, it would have to be extensively reprogrammed. As an alternative, such a calculation could be done “off line” by adding another layer of post processing after CALPOST. To this end, I have developed a processor, in the form of an Excel workbook, that takes the CALPOST “Ranked Daily Visibility Change: Modeled Extinction by Species” output table, referenced against default annual average natural conditions concentrations, and creates an equivalent table of results based on the new algorithm. It can also incorporate the visibility impact due to light absorption by NO_2 in the plume.

The following describes the science behind the processor (which we’ll call the CALPOST-IMPROVE Processor) and provides instructions for using it.

Concepts

In addition to the mechanical changes imposed by all the new terms in the new IMPROVE formula, applying the new algorithm also requires some conceptual changes. The biggest of these is that the extinction efficiencies of sulfates, nitrates, and organics now depend on the concentrations of those species. The practical implication of this is that extinction is no longer linearly additive. To calculate total extinction, you cannot take a background level of extinction and add to it CALPOST’s calculation of extinction caused by the particulate matter coming from a source, because when the two aerosols mix in the atmosphere their combined mass concentration results in increases in the extinction efficiencies of both the background and the source contribution. This means that combining background particulate matter with the particulate matter from a source gives an extinction result that is greater than the sum of the two separate extinctions.

With the nonlinear behavior resulting from applying the new IMPROVE algorithm, the extinction impact of the source (i.e., the increase in extinction resulting from introducing source emissions into the atmosphere) is the sum of three parts:

1. The source impact calculated by the new IMPROVE algorithm using the CALPOST outputs for a plume in isolation;

³ *Revised IMPROVE Algorithm for estimating Light Extinction from Particle Speciation Data*. Report to IMPROVE Steering Committee, November 2005.

2. An increase in that source impact because the extinction efficiency increases when the source's aerosol combines with the background aerosol; and correspondingly,
3. An increase in the extinction of the background aerosol because of that same mixing.

The total new extinction is the sum of the above three components plus the original background extinction. The original background extinction is just that calculated by the new IMPROVE algorithm from background concentrations of the various components, without any consideration of the effects of the plume. For this application, the background is taken to be that described by EPA's default natural conditions. The difference between the total extinction and the background is the impact of the source.

More details about the calculation are given in the appendix.

Description of Processor

The CALPOST-IMPROVE Processor is a Microsoft Excel workbook that consists of four worksheets. In Version 2 the worksheets are the following.

1. Input & Output – The output table from CALPOST is imported to here and user entries are made for the Rayleigh scattering coefficient and, if desired, for a sea salt concentration at the Class I area of interest. The NO_x concentration on each day attributable to the emissions from the source can also be entered together with an assumption of what fraction of the NO_x is in the form of NO_2 . A revised table, with extinction based on the new IMPROVE algorithm is then presented on the same page. This is the only page on which user input takes place, and the results of the calculations appear on this page.
2. Calculations -- The calculations themselves are all done on this worksheet. There is no user input to this page. The variables are explained on the worksheet itself, so the user can find intermediate values if so inclined.
3. F(RH) – This worksheet tabulates the traditional IMPROVE $f(\text{RH})$ against RH, and then also lists values for the three new humidity growth functions, $f_s(\text{RH})$, $f_L(\text{RH})$, and $f_{ss}(\text{RH})$. It serves as a lookup table for the "Calculations" worksheet.
4. Rayleigh & Sea Salt – This page tabulates the IMPROVE-recommended Rayleigh scattering coefficients for all VISTAS Class I areas and for Class I areas in adjacent states. It also lists the average sea salt concentrations for the same locations, as tabulated on the VIEWS web site, based on chloride or chlorine measurements by IMPROVE monitors between 2000 and 2004. This sheet just provides information for the user; it is not linked to the rest of the workbook. The user can obtain Rayleigh and sea salt numbers for the Class I area of interest from this table and then manually enter them in the designated spaces in worksheet 1.

Instructions for Using the CALPOST-IMPROVE Processor

These instructions apply to Version 2 of the processor. Version 2 includes the ability to calculate the light extinction effects of NO₂ resulting from the source's emissions.

Step 1. Begin by opening the output (.LST) file from a CALPOST visibility calculation run in a text editor or word processing program.⁴ In the second half of the file, locate the table "Ranked Daily Visibility Change" with the subheading "Modeled Extinction by Species".⁵

Step 2. Copy this table and paste it onto a new page. Save it as a text (.txt) file, not as a formatted (e.g., MS Word .doc or .rtf) file. The final table should contain only the column headings and the data. Delete all other captions, any additional data summaries at the end, and blank lines before or after the table. The processor can handle a maximum of 22 lines of data (i.e., the highest rank in the last, unlabeled, column should be 22) plus a row of column captions. Delete any data that exceed this limit. (Fewer than 22 lines of data are OK.) The result should look like the example in Figure 1, although the line wrapping may differ.

Step 3. Open the CALPOST-IMPROVE Processor in Microsoft Excel. Save the open file under a new name so that the original empty processor will remain available for future use. The front worksheet, labeled "Input & Output" looks like Figure 2. There is a large empty box, surrounded by double lines, into which the table created above will be imported, as described below.⁶ On the right is a box into which NO_x concentrations may be entered manually, and a small box below this box is provided for entry of the user's assumption of what fraction of that NO_x is in the form of NO₂. Two smaller boxes provide for user input of the Rayleigh scattering coefficient and, optionally, sea salt concentration for the Class I area, as described below. Results of the new IMPROVE algorithm calculations appear in blue in the lower half of the worksheet and some additional results, that are also useful for quality control, appear in green to the right of the large box. At the moment, many results cells will display nonsensical numbers and error messages, such as shown in Figure 2.

Step 4. Select the upper left cell (A7) in the large box. On the Excel menu bar, go to *Data>Get External Data* and click on *Import Text File*.⁷ (If the large box is not empty, click on *Edit Text Import* instead.) Select the file that contains the table created in Step 2 and click on the *Get Data* button. Go through the Text Import Wizard steps, checking that all values appear correctly in separate columns. (The label "COORDINATES (km)" will be split over two columns; this is OK.) When everything appears in order, click *Finish*.

⁴ The background concentrations that were entered into CALPOST must be the EPA-prescribed default annual average natural conditions concentrations for the East. The processor will not give correct answers if other concentrations were used in CALPOST.

⁵ For future reference in Step 7, this may also be a good time to locate the table with the same title but with the subtitle "% of Modeled Extinction by Species", which appears later in the output file.

⁶ If the workbook has already been used, the boxes may not be empty. This does not matter.

⁷ The exact wording may vary slightly between different versions of Microsoft Excel. The terminology used here is from Excel 2004 for Macintosh.

YEAR	DAY	HR	RECEPTOR	COORDINATES (km)			TYPE	BEXT(Model)			BEXT(BKG)
BEXT(Total)				%CHANGE	F(RH)	bxSO4	bxNO3	bxOC	bxEC	bxPMC	bxPMF
2002	175	0	1027			1479.069	24.683	D	5.495		21.650
25.38	3.500	5.401	0.045	0.042	0.002	0.001	0.004	1			27.145
2002	172	0	1021			1479.244	23.778	D	4.923		21.650
22.74	3.500	4.475	0.404	0.030	0.001	0.001	0.004	2			26.573
2002	284	0	1045			1484.348	27.580	D	3.150		21.470
14.67	3.300	2.684	0.428	0.033	0.001	0.001	0.003	3			24.620
2002	353	0	1026			1482.762	24.457	D	2.594		21.290
12.18	3.100	2.017	0.557	0.018	0.001	0.000	0.002	4			23.884
2002	283	0	1026			1482.762	24.457	D	2.502		21.470
11.65	3.300	2.269	0.201	0.028	0.001	0.001	0.003	5			23.972
2002	195	0	1045			1484.348	27.580	D	2.011		21.830
9.21	3.700	1.963	0.031	0.015	0.001	0.000	0.001	6			23.841
2002	29	0	1117			1486.636	34.592	D	1.872		21.200
8.03	3.000	1.542	0.320	0.009	0.000	0.000	0.001	7			23.072
2002	173	0	1128			1479.259	35.042	D	1.649		21.650
7.62	3.500	1.625	0.012	0.010	0.000	0.000	0.001	8			23.299
2002	234	0	1021			1479.244	23.778	D	1.524		22.190
6.87	4.100	1.482	0.029	0.011	0.000	0.000	0.001	9			23.714
2002	298	0	1021			1479.244	23.778	D	1.459		21.470
6.80	3.300	1.284	0.160	0.014	0.001	0.000	0.001	10			22.929
2002	299	0	1021			1479.244	23.778	D	1.436		21.470
6.69	3.300	1.281	0.140	0.013	0.000	0.000	0.001	11			22.906
2002	275	0	1026			1482.762	24.457	D	1.270		21.470
5.92	3.300	1.202	0.058	0.009	0.000	0.000	0.001	12			22.740
2002	263	0	1045			1484.348	27.580	D	1.237		21.470
5.60	4.000	1.223	0.008	0.005	0.000	0.000	0.001	13			22.100
2002	252	0	1026			1482.762	24.457	D	1.189		23.337
5.38	4.000	1.166	0.013	0.009	0.000	0.000	0.001	14			23.289
2002	285	0	1021			1479.244	23.778	D	0.992		22.100
4.62	3.300	0.813	0.179	0.001	0.000	0.000	0.000	15			22.462
2002	161	0	1026			1482.762	24.457	D	0.873		21.650
4.03	3.500	0.842	0.020	0.009	0.000	0.000	0.001	16			22.523
2002	150	0	1026			1482.762	24.457	D	0.857		21.380
4.01	3.200	0.822	0.026	0.007	0.000	0.000	0.001	17			22.237
2002	340	0	1140			1481.017	37.258	D	0.817		21.290
3.84	3.100	0.663	0.153	0.001	0.000	0.000	0.000	18			22.107
2002	151	0	1117			1486.636	34.592	D	0.745		21.380
3.49	3.200	0.704	0.033	0.007	0.000	0.000	0.001	19			22.125
2002	160	0	1021			1479.244	23.778	D	0.735		21.650
3.40	3.500	0.710	0.014	0.010	0.000	0.000	0.001	20			22.385
2002	346	0	1021			1479.244	23.778	D	0.703		21.290
3.30	3.100	0.620	0.080	0.002	0.000	0.000	0.000	21			21.993
2002	247	0	1021			1479.244	23.778	D	0.661		22.100
2.99	4.000	0.654	0.004	0.002	0.000	0.000	0.000	22			22.761

Figure 1. Example of CALPOST Output Table, in Proper Format for Importing into the CALPOST-IMPROVE Processor.

Step 5.⁸ The “Import Data” window will appear, with cell A7 indicated as the location at which data will be entered. Click on the *Properties* button. In the window that appears, select “Overwrite existing cells with new data, clear unused cells” and uncheck “Adjust column width”, then click on *OK*. Now click on the *OK* button in the “Import Data” window.

Step 6. Assuming that your Excel application is set up to automatically recalculate whenever any entries are changed, you should now have filled the cells in the large box on the first worksheet,

⁸ If the processor already had data in it and *Edit Text Import* was clicked in Step 4, then the “Import Data” window will not appear and Step 5 can be skipped.

[illegible]

Figure 2. Example of Appearance of Input & Output Worksheet before Data Entry.

numbers should have appeared in the green columns to the right, and some numbers will have appeared in the output table in blue on the lower half of the worksheet. If the data import worked properly, none of the imported data should have spilled out of the large box. Check that all the column captions in bold outside the large box are now duplicated on the first line in the box. (There won't be a caption for Rank.)

Step 7. As a further check on whether everything is correct so far, the dv information in the three columns to the right of the large box should be the same as that in the second CALPOST table "Ranked Daily Visibility Change: % of Modeled Extinction by Species", which was mentioned in Footnote 1.

Step 8. Beneath the large box that was just filled with imported data, enter the Rayleigh scattering coefficient for the Class I area of interest into the top small box after red instruction 3. Also, if you wish, fill in the other small box, the one after red instruction 4, with the annual average sea salt concentration. (The sea salt box may be left blank, but the Rayleigh scattering coefficient box must be filled in.) To help with filling in these two boxes, the fourth worksheet, "Rayleigh & Sea Salt", provides IMPROVE-calculated values of the Rayleigh coefficients for Class I areas in the VISTAS region and in adjacent states. Also, average sea salt concentrations for 2000-2004, calculated in accordance with the new IMPROVE procedures, can be found there.

Step 9.⁹ If the impact due to NO₂ is to be considered, a second CALPOST run will be needed to provide the 24-hr average NO_x concentrations estimated by CALPUFF. For this purpose, run CALPOST using the ASPEC = NOX option in Input Group 1 of the CALPOST.INP control file. The NO_x values to insert in the NO_x input box on the Input & Output page of the processor have to be extracted manually from the CALPOST output file for each date and receptor listed in the file that was imported in Steps 1 through 5 above and are displayed in the left hand columns in the large box.

Step 10. Select a value between 0 and 1 to represent what fraction of NO_x is in the form of NO₂. Enter this value into the small box at red instruction 6 below the column where the NO_x concentrations were entered.¹⁰

Step 11. The blue data table at the bottom of the page represents the new IMPROVE algorithm outputs. An example is shown in Figure 3. This table can be compared with the original CALPOST table at the top of the page. All of the columns in both tables show exactly the same variables, except that the F(RII) column in the top table is replaced by just the RII in the lower table (since the new procedure has three different f(RII) functions) and a new baNO₂ column has been added to the bottom table to show the light absorption due to NO₂ (in Mm⁻¹). Although the events are listed in the same order in both tables, note that their rankings may have changed, as is the case for many of the lines in the blue output table in Figure 3.

⁹ Steps 8 and 9 are optional. If the impact due to NO₂ is not of interest, just leave the entry fields mentioned in these steps blank.

¹⁰ An easy way to see the effect of the NO₂ on the source's impact in the output table in the lower half of the page is to toggle this NO₂/NO_x value between the selected value and zero.

For those who are interested in more detail concerning the calculations that take place, values of the three $f(RH)$ functions appear in columns M through O on the second, "Calculations" spreadsheet. The extinction impact of the source, including enhancement of the extinction efficiencies for sulfates, nitrates, and organics because of greater total mass concentrations, appears in columns V through AC. Extinction due to the annual average natural background appears in Columns AJ through AN; natural background extinctions for those components that are enhanced by greater total mass concentrations appear in columns AU through AX.

CALPOST Recalculation with New IMPROVE Algorithm																						
----- INPUT from CALPOST (based on old IMPROVE algorithm) -----																						
1. At cell A7, import "Ranked Daily Visibility Change" (best) table, including column headings, from CALPOST (22 days, max)										2. Check calculated values below against CALPOST's "Ranked Daily Visibility Change" (dv) table												
3. Enter value of site-specific Rayleigh scattering coefficient, from "Rayleigh & Sea Salt" worksheet										4. (Optional) Insert annual average sea salt concentration, from "Rayleigh & Sea Salt" worksheet. Leave blank if not used, i.e. default is 0.												
5. (Optional) Enter desired NO2/NOx ratio (default is 0)										6. (Optional) Enter 24hr NOx conc. NOx(ppb)												
YEAR DAY	HR	RECEPTOR	COORDINATE X (km)	COORDINATE Y (km)	TYPE	BEXT(Mode)	BEXT(BKG)	BEXT(Tot)	%CHANGE	R(RH)	bsSO4	bsNO3	bsOC	bsEC	bsPMC	bsPNC	Rank	dv(tot)	dv(bkg)	adv		
2002 175	0	1027	1479.069	24.603	0	4.925	21.65	27.145	25.38	5.5	5.401	0.045	0.002	0.002	0.001	0.004	3	9.95	7.70	2.25		
2002 172	0	1021	1479.244	23.778	0	4.925	21.65	26.573	22.74	3.5	4.475	0.044	0.003	0.003	0.001	0.001	0.004	2	9.77	7.70	2.07	
2002 204	0	1045	1404.340	27.580	0	2.503	21.47	24.62	14.87	3.2	2.604	0.425	0.023	0.001	0.001	0.003	2	9.01	7.64	1.37		
2002 352	0	1026	1402.762	24.457	0	2.044	21.29	23.884	10.16	3.5	2.017	0.157	0.016	0.002	0	0.002	4	9.71	7.60	1.54		
2002 282	0	1026	1402.762	24.457	0	2.005	21.47	23.972	11.65	3.2	2.269	0.201	0.030	0.001	0.001	0.003	3	9.74	7.64	1.36		
2002 195	0	1045	1404.340	27.580	0	2.113	21.62	23.041	9.21	3.7	1.983	0.232	0.015	0.001	0	0.001	8	9.85	7.61	2.08		
2002 30	0	1117	1406.536	34.592	0	1.072	21.82	23.072	8.02	3	1.542	0.32	0.009	0	0	0.001	7	9.36	7.61	0.92		
2002 173	0	1128	1479.259	35.542	0	1.849	21.85	23.299	7.62	3.5	1.825	0.012	0.01	0	0	0.001	8	9.69	7.62	0.73		
2002 234	0	1021	1479.244	23.778	0	1.634	22.19	24.714	6.87	4.3	1.490	0.029	0.001	0	0	0.001	4	9.64	7.67	0.56		
2002 290	0	1021	1479.244	23.778	0	1.455	21.47	22.929	6.83	3.3	1.284	0.16	0.014	0.001	0	0.001	10	9.38	7.64	0.56		
2002 399	0	1021	1479.244	23.778	0	1.396	21.79	23.908	6.89	3.3	1.281	0.14	0.013	0	0	0.001	11	9.37	7.64	0.56		
2002 276	0	1026	1402.762	24.457	0	1.27	21.60	23.734	5.92	3.4	1.102	0.054	0.009	0	0	0.001	12	9.28	7.64	0.57		
2002 262	0	1045	1404.340	27.580	0	1.237	22.1	23.337	5.6	4	1.223	0.205	0.002	0	0	0.001	13	9.27	7.63	0.54		
2002 252	0	1026	1402.762	24.457	0	1.189	22.1	23.269	5.26	4	1.166	0.013	0.009	0	0	0.001	14	9.44	7.63	0.53		
2002 205	0	1021	1479.244	23.778	0	0.992	21.47	22.462	4.62	3.2	0.813	0.179	0.001	0	0	0	15	9.09	7.64	0.49		
2002 162	0	1026	1402.762	24.457	0	0.479	21.65	22.523	4.03	3.8	0.892	0.02	0.009	0	0	0.001	16	9.18	7.62	0.40		
2002 150	0	1021	1402.762	24.457	0	0.857	21.29	22.927	4.01	3.2	0.892	0.029	0.007	0	0	0.001	17	7.97	7.60	0.39		
2002 342	0	1140	1401.017	37.250	0	0.617	21.22	22.197	3.94	3.3	0.663	0.172	0.001	0	0	0	10	7.93	7.56	0.38		
2002 153	0	1117	1406.536	34.592	0	0.745	21.39	22.125	3.49	3.2	0.704	0.081	0.007	0	0	0.001	18	7.94	7.60	0.34		
2002 160	0	1021	1479.244	23.778	0	0.735	21.05	22.385	2.4	3.5	0.71	0.014	0.01	0	0	0.001	20	7.09	7.62	0.29		
2002 345	0	1021	1479.244	23.778	0	0.703	21.29	21.993	2.2	3.2	0.62	0.005	0.002	0	0	0	21	7.09	7.56	0.32		
2002 247	0	1021	1479.244	23.778	0	0.561	22.1	22.761	2.99	4	0.694	0.004	0.002	0	0	0	22	8.22	7.62	0.26		
3. Enter value of site-specific Rayleigh scattering coefficient, from "Rayleigh & Sea Salt" worksheet										11	4. Enter desired NO2/NOx ratio (default is 0)										0.7	
4. (Optional) Insert annual average sea salt concentration, from "Rayleigh & Sea Salt" worksheet. Leave blank if not used, i.e. default is 0.										0.02												
----- OUTPUT (based on new IMPROVE algorithm) -----																						
YEAR DAY	HR	RECEPTOR	COORDINATE X (km)	COORDINATE Y (km)	TYPE	BEXT(Sources)	BEXT(BKG)	BEXT(Tot)	%CHANGE	RH(%)	bsSO4	bsNO3	bsOC	bsEC	bsPMC	bsPNC	bsNO2	Rank	dv(tot)	dv(bkg)	adv	
2002 175	0	1027	1479.069	24.603	0	4.925	22.04	27.010	22.56	82	4.203	0.026	0.003	0.003	0.002	0.001	0.024	4.456	1	9.94	7.60	2.33
2002 172	0	1021	1479.244	23.778	0	4.312	22.04	25.187	19.86	95	2.604	0.144	0.029	0.008	0.001	0.001	0.194	2	9.62	7.60	1.72	
2002 204	0	1045	1404.340	27.580	0	2.563	21.75	24.365	11.06	84	2.076	0.227	0.026	0.001	0.001	0.003	0.259	3	9.02	7.59	1.37	
2002 352	0	1026	1402.762	24.457	0	2.174	21.57	23.780	10.15	82	1.528	0.145	0.016	0.001	0	0	0.002	1.715	5	9.65	7.49	1.37
2002 282	0	1026	1402.762	24.457	0	2.092	21.79	24.060	10.61	84	1.752	0.167	0.002	0.001	0.001	0.002	0.247	4	8.79	7.58	1.01	
2002 195	0	1045	1404.340	27.580	0	1.708	22.21	23.926	7.75	87	1.569	0.227	0.032	0.001	0	0.001	0.299	6	9.73	7.60	0.75	
2002 30	0	1117	1406.536	34.592	0	1.825	21.49	23.139	7.62	83	1.16	0.28	0.007	0	0	0.001	0.298	7	9.88	7.64	0.73	
2002 173	0	1128	1479.259	35.542	0	1.812	22.04	23.667	7.37	85	1.247	0.01	0.008	0	0	0.001	0.247	8	9.61	7.60	0.71	
2002 234	0	1021	1479.244	23.778	0	1.646	22.64	24.199	8.97	82	1.218	0.026	0.009	0	0	0.001	0.247	9	9.82	7.60	0.71	
2002 290	0	1021	1479.244	23.778	0	1.309	21.73	23.990	5.29	84	0.988	0.123	0.031	0.001	0	0.001	0.274	13	8.32	7.78	0.54	
2002 399	0	1021	1479.244	23.778	0	1.237	21.79	23.027	5.72	84	0.988	0.217	0.031	0	0	0.001	0.224	12	8.34	7.78	0.56	
2002 276	0	1026	1402.762	24.457	0	1.164	21.78	23.949	4.84	84	0.606	0.044	0.007	0	0	0.001	0.178	14	9.30	7.78	0.52	
2002 262	0	1045	1404.340	27.580	0	1.137	22.24	21.793	5.06	85	1.026	0.007	0.004	0	0	0.001	0.099	16	9.66	8.17	0.49	
2002 252	0	1026	1402.762	24.457	0	1.369	22.64	24.015	8.05	89	0.970	0.012	0.007	0	0	0.001	0.271	10	9.76	8.17	0.59	
2002 206	0	1021	1479.244	23.778	0	1.245	21.78	23.031	5.74	84	0.606	0.144	0.004	0	0	0	0.47	11	9.44	7.78	0.56	
2002 162	0	1026	1402.762	24.457	0	1.116	22.04	23.165	5.09	80	0.57	0.017	0.007	0	0	0.001	0.421	13	9.40	7.60	0.50	
2002 160	0	1026	1402.762	24.457	0	0.997	21.67	22.669	4.69	83	0.602	0.021	0.005	0	0	0.001	0.347	18	9.18	7.79	0.46	
2002 340	0	1140	1401.017	37.250	0	1.071	21.57	22.646	4.99	82	0.5	0.125	0.004	0	0	0	0.446	17	9.17	7.69	0.49	
2002 192	0	1117	1406.536	34.592	0	0.913	21.67	22.384	4.24	81	0.532	0.027	0.008	0	0	0.001	0.347	20	9.15	7.73	0.42	
2002 160	0	1021	1479.244	23.778	0	0.939	22.04	23.960	4.25	80	0.565	0.010	0.008	0	0	0.001	0.347	19	9.22	7.80	0.49	
2002 345	0	1021	1479.244	23.778	0	0.632	21.57	22.200	2.95	82	0.467	0.265	0.002	0	0	0	0.299	21	7.90	7.69	0.29	
2002 247	0	1021	1479.244	23.778	0	0.552	22.64	23.155	2.46	83	0.548	0.004	0.002	0	0	0	0	22	9.41	8.17	0.26	

Figure 3. Example of Appearance of Finished Input & Output Worksheet.

Appendix Details of Calculation Approach

As an example of the calculation steps, assume that the sulfate concentration resulting from emissions from a source is $[S_E]$ and the sulfate in the undisturbed natural background is $[S_N]$, for a total ambient sulfate concentration of $[S_T]$. According to Equations 1 and 2 in the main body of this document, the total extinction due to sulfate for this combination is

$$b_{ext}(sulfate) = 2.2 \cdot f_S(RH) \cdot [small\ sulfate] + 4.8 \cdot f_L(RH) \cdot [large\ sulfate], \quad (\text{Eq. A-1})$$

where

$$\begin{aligned} [large\ sulfate_T] &= \{[S_T]/20\} \cdot [S_T] \text{ if } [S_T] < 20 \mu g^3 \\ [large\ sulfate_T] &= [S_T] \text{ if } [S_T] \geq 20 \mu g/m^3 \\ [small\ sulfate_T] &= [S_T] - [large\ sulfate_T], \end{aligned} \quad (\text{Eqs. A-2})$$

and the subscript T denotes total sulfate

For the original background, where there is no source impact, the corresponding formulas for the terms in Equations A-2 are

$$\begin{aligned} [large\ sulfate_N] &= \{[S_N]/20\} \cdot [S_N] \text{ if } [S_N] < 20 \mu g^3 \\ [large\ sulfate_N] &= [S_N] \text{ if } [S_N] \geq 20 \mu g/m^3 \\ [small\ sulfate_N] &= [S_N] - [large\ sulfate_N], \end{aligned} \quad (\text{Eqs. A-3})$$

where the subscript N denotes natural sulfate.

Similar calculations need to be carried out for nitrates. Contributions of the other particulate components are linear and can just be calculated according to Equation 1.

If the impact due to NO_2 is also to be considered, then the source impact due to this component is, according to Equation 1,

$$b_{ext}(NO_2) = 0.33 \cdot [NO_2], \quad (\text{Eq. A-4})$$

where $[NO_2]$ is in ppb. It is reasonable to assume that the ambient NO_2 concentrations under natural conditions would be so small as to cause negligible light absorption, so the corresponding term is not needed in the natural conditions calculation.

The contributions due to the various components are summed together as in Equation 1 to obtain the total extinction $b_{ext,T}$ and the natural background extinction $b_{ext,N}$. The

fractional change in extinction is then calculated as the difference, normalized by the natural background extinction

$$(b_{ext,T} - b_{ext,N})/b_{ext,N} \quad (\text{Eq. A-5})$$

a result that can also be expressed in deciviews.

These formulas are used in the CALPOST-IMPROVE Processor. Similar formulas apply for nitrates and organics. There is no nonlinearity in the remaining terms in Equation 1.

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Appendix D

Burns Harbor Four-Factor Analysis Submittal

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Regional Haze Four-Factor Analysis with Visibility Benefits Evaluation for NO_x and SO₂ Emissions Control

- *Battery Nos. 1 and 2*
- *Clean Coke Oven Gas Export Line*
- *Power Station Boiler Nos. 7-12*
- *Blast Furnaces C and D*

Prepared for
ArcelorMittal Burns Harbor, LLC

September 30, 2020

Regional Haze Four-Factor Analysis with Visibility Benefits Evaluation for NO_x and SO₂ Emissions Control

September 30, 2020

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Appendix D	2008 ArcelorMittal Burns Harbor BART Modeling Report

Abbreviations

2010 Nucor BACT	Nucor Steel Louisiana Best Available Control Technology Analyses, March 1, 2010
2019 RH SIP Guidance	EPA Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 20, 2019
AOI	Area of Influence
BACT	best available control technology
Barr	Barr Engineering
BART	best available retrofit technology
BH	ArcelorMittal Burns Harbor
CENRAP	Central Regional Air Planning Association
CenSARA	Central States Air Resources Agencies
dv	deciview
EPA	U.S. Environmental Protection Agency
EPA Control Cost Manual	EPA Air Pollution Control Cost Manual
FLAG	Federal Land Managers' Air Quality Related Values Work Group
FGD	Flue-gas desulfurization
IDEM	Indiana Department of Environmental Management
II&S mills	Integrated Iron and Steel Mills
IMPROVE	Interagency Monitoring of Protected Visual Environments
Isle Royale	Isle Royale National Park
km	kilometer
LADCO	Lake Michigan Air Directors Consortium
LAER	lowest achievable emission rate
LNB	Low-NO _x Burners
Mammoth Cave	Mammoth Cave National Park
Mingo	Mingo National Wildlife Refuge
NO _x	nitrogen oxides
O&M	operating and maintenance
PM	particulate matter
PSAT	Particulate Matter Source Apportionment Technology
PSD	Prevention of Significant Deterioration
RACT	reasonably available control technology
RBLC	RACT/BACT/LAER Clearinghouse
RFI	Request for Information
RHR	Regional Haze Rule
SCR	Selective Catalytic Reduction
Seney	Seney National Wildlife Refuge
SIP	State Implementation Plan
SO ₂	sulfur dioxide

tpy	tons per year
URP	Universal Rate of Progress
VISTAS	Visibility Improvement State and Tribal Association of the Southeast

1 Executive Summary

In accordance with the Indiana Department of Environmental Management's (IDEM's) June 18, 2020 Request for Information (RFI) Letter,¹ ArcelorMittal Burns Harbor (BH) evaluated potential emission control measures for nitrogen oxides (NO_x) and sulfur dioxide (SO₂) for the Clean Coke Oven Gas Export Line, Battery Nos. 1 and 2, Power Station Boiler Nos. 7-12, and Blast Furnaces C and D². This report addresses the four statutory factors, laid out in 40 CFR 51.308(f)(2)(i), for the reasonable set of emission control measures pursuant to the final U.S. Environmental Protection Agency (EPA) Regional Haze Rule (RHR) State Implementation Plan (SIP) guidance³ that was issued on August 20, 2019 (2019 RH SIP Guidance). The four statutory factors are as follows:

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, commonly referred to as a four-factor analysis, describes the background and analysis for identifying the reasonable set of emission control measures and conducting the review of the four statutory factors. Additionally, this analysis evaluates the potential for visibility benefits at the associated Class I areas from the installation of additional emission control measures, consistent with the 2019 RH SIP Guidance. However, data and information from the Lake Michigan Air Directors Consortium (LADCO) necessary to complete CAMx air quality modeling as part of the visibility benefits analysis was unavailable at the time of this report submission. BH reserves the right to amend and/or supplement this report and analysis once CAMx modeling has been completed.

As described in Section 3, the Coke Oven Battery Nos. 1 and 2 four-factor analyses with visibility benefits evaluations concluded that:

- There is no reasonable set of NO_x emission control measures beyond what is currently installed and operated for the Coke Oven Battery Nos. 1 and 2 units. The reasonable set of additional NO_x emission control measures is not technically feasible for these emission units.

¹ June 18, 2020 letter from Mathew Stuckey of IDEM to Robert Maciel of ArcelorMittal Burns Harbor, LLC.

² IDEM's June 18, 2020 letter refers to Blast Furnaces C and D as "Blast Furnace Nos. 3 and 4".

³ US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003.

- The reasonable set of SO₂ emission control measures beyond what is currently installed and operated for these emission units consists of spray dryer absorbers⁴ or a coke oven gas desulfurization plant⁵.
- The associated SO₂ cost-effectiveness values (\$ per ton of emissions reduction) of the reasonable set of additional SO₂ emission control measures are not reasonable.
- Independent of the four-factor analysis, additional NO_x and SO₂ emission reductions are not appropriate and are unnecessary for these sources because:
 - The 5-year average visibility impairment on the most impaired days at the associated Class I areas of interest is already below (Mammoth Cave National Park (Mammoth Cave, 492 km), Seney National Wildlife Refuge (Seney, 511 km), and Isle Royale National Park (Isle Royale, 708 km)), or trending towards and expected to attain without additional emission reductions (Mingo National Wildlife Refuge (Mingo, 568 km)), the 2028 Universal Rate of Progress (URP) (see Section 6.1), and
 - The visibility impacts analysis completed to date indicates that BH is not a contributor to perceptible⁶ visibility impairment to the Class I areas on the most impaired days, thus any installation of additional emission control measures at BH is not expected to have a perceptible impact on visibility in affected Class I areas and no further visibility improvements are necessary to meet the 2028 URP (see Section 6.3). Further analysis through CAMx modeling that is underway is anticipated to show that BH does not have a perceptible visibility impact on these Class I areas. BH reserves the right to amend and/or supplement this report and visibility analysis once CAMx modeling has been completed.
- Therefore, the Coke Oven Battery Nos. 1 and 2 existing NO_x and SO₂ emission performance are sufficient for the IDEM's regional haze reasonable progress goal.

Also as described in Section 3, the Clean Coke Oven Gas Export Line and Flare four-factor analyses with visibility benefits evaluations concluded that:

⁴ Spray dryer absorber systems spray lime slurry into an absorption tower where SO₂ is absorbed by the slurry, forming CaSO₃/CaSO₄. The liquid-to-gas ratio is such that the water evaporates before the droplets reach the bottom of the tower. The dry solids are collected with a fabric filter downstream.

⁵ Coke oven gas desulfurization occurs via the installation of sulfur recovery and Claus off-gas treating units to remove sulfur from the gas stream and produce an elemental sulfur byproduct.

⁶ Federal Register Vol. 70, No. 128, 07/06/2005, Page 39119. (<https://www.federalregister.gov/documents/2005/07/06/05-12526/regional-haze-regulations-and-guidelines-for-best-available-retrofit-technology-bart-determinations>)

- There is no reasonable set of NO_x emission control measures for the Clean Coke Oven Gas Export Flare beyond what is currently installed and operated for this emission unit. There is no available set of additional NO_x emission control measures for this emission unit.
- It is not appropriate to evaluate NO_x emission control measures on the Clean Coke Oven Gas Export Line as it is simply a distribution line to other downstream sources, which have been independently evaluated as needed.
- The reasonable set of SO₂ emission control measures for the Clean Coke Oven Gas Export Line and Flare beyond what is currently installed and operated consists of coke oven gas desulfurization⁵.
- The associated SO₂ cost-effectiveness value (\$ per ton of emissions reduction) of the reasonable set of additional SO₂ emission control measures is not reasonable.
- As described in the Coke Oven Battery Nos. 1 and 2 conclusion above, additional NO_x and SO₂ emission reductions are not appropriate and are unnecessary for the Clean Coke Oven Gas Export Line and Flare, independent of the four-factor analysis, because BH is not expected to have a perceptible impact on visibility in affected Class I areas and no further visibility improvements are necessary to meet the 2028 URP (see Section 6).
- Therefore, the Clean Coke Oven Gas Export Line and Flare existing NO_x and SO₂ emission performance are sufficient for the IDEM's regional haze reasonable progress goal.

As described in Section 4, the Power Station Boiler Nos. 7-12 four-factor analyses with visibility benefits evaluations concluded that:

- There is no reasonable set of NO_x emission control measures beyond what is currently installed and operated for Power Station Boiler Nos. 7-12. The reasonable set of additional NO_x emission control measures is not technically feasible for these emission units.
- The reasonable set of SO₂ emission control beyond what is currently installed and operated for this emission unit consists of spray dryer absorbers, dry sorbent injection⁷ or a coke oven gas desulfurization plant.
- The associated SO₂ cost-effectiveness values (\$ per ton of emissions reduction) of the reasonable set of additional SO₂ emission control measures are not reasonable.
- As described in the Coke Oven Battery Nos. 1 and 2 conclusion above, additional NO_x and SO₂ emission reductions are not appropriate and are unnecessary for the Power Station Boiler Nos. 7-

⁷ Dry sorbent (pulverized lime or limestone) is directly injected into the duct upstream of a new fabric filter. SO₂ reacts with the sorbent, and the solid particles are collected with a fabric filter. Further SO₂ removal occurs as the flue gas flows through the filter cake on the bags.

12, independent of the four-factor analysis, because BH is not expected to have a perceptible impact on visibility in affected Class I areas and no further visibility improvements are necessary to meet the 2028 URP (see Section 6).

- Therefore, the Power Station Boiler Nos. 7-12 existing NO_x and SO₂ emission performance are sufficient for the IDEM's regional haze reasonable progress goal.

As described in Section 5, the Blast Furnaces C and D four-factor analyses with visibility benefits evaluations concluded that:

- There is no reasonable set of NO_x and SO₂ emission control measures beyond what is currently installed and operated for these emission units. The reasonable set of additional NO_x emission control measures either represent no or negligible emission reduction potential and may otherwise be technically infeasible for these emission units.
- As described in the Coke Oven Battery Nos. 1 and 2 conclusion above, additional NO_x and SO₂ emission reductions are not appropriate and are unnecessary for Blast Furnaces C and D, independent of the four-factor analysis, because BH is not expected to have a perceptible impact on visibility in affected Class I areas and no further visibility improvements are necessary to meet the 2028 URP (see Section 6).
- Therefore, the Blast Furnaces C and D existing NO_x and SO₂ emission performance are sufficient for the IDEM's regional haze reasonable progress goal.

The NO_x and SO₂ four-factor analyses with visibility benefits evaluations conclusions are summarized in Table 1-1 and Table 1-2, respectively.

As discussed above, in addition to the four statutory factors, this report also considers the current visibility and the potential visibility benefits to applicable Class I areas (the closest of which is nearly 500 km away from BH) from installing additional emission control measures on the associated sources at the facility. An analysis of current visibility conditions was completed for Mammoth Cave (492 km), Mingo (568 km), Seney (511 km), and Isle Royale (708 km). The analysis compared the current visibility conditions to the natural visibility goal, the 2028 URP, and to the possible reasonable progress goals for the SIP. As shown in Section 6.1, the 5-year average visibility impairment on the most impaired days is already below the 2028 URP (Mammoth Cave (492 km), Seney (511 km) and Isle Royale (708 km)), or trending towards and expected to attainment to the 2028 URP (Mingo (568 km)) without additional emission reductions. Furthermore, there are other emission reductions that are already planned to occur prior to 2028 which will continue to improve the visibility in these Class I areas. For example, several electrical utilities intend to transition away from coal-fired generation to a more diverse generation mix that includes a combination of wind, solar, natural gas and storage. Thus, it is not necessary for BH to install additional emission control measures for reasonable progress to occur at these distant Class I areas.

Moreover, a visibility impacts analysis was conducted for these same Class I areas (Mammoth Cave (492 km), Mingo (568 km), Seney (511 km) and Isle Royale (708 km)) to determine how emissions from BH could impact visibility in Class I areas on the 20% most impaired days. As shown in Section 6.3.1, the

previous CALPUFF modeling conducted demonstrates that the facility does not contribute to visibility impairment; this analysis is still relevant and appropriate based on the overly conservative nature of the analysis. Likewise, the recent visibility impacts screening analyses conducted by two regional planning organizations demonstrated that no additional control measures analyses were necessary for BH because the visibility impacts were less than the screening thresholds which were applied (see Section 6.3.2). Additionally, a back-trajectory analysis was conducted for Seney (511 km) and Isle Royale (708 km) that demonstrates emission reductions at BH are unlikely to improve visibility on the most impaired days at these Class I areas (see Section 6.3.3). Finally, further analysis through CAMx modeling that is underway is anticipated to show that BH does not have a perceptible visibility impact on these Class I areas. BH reserves the right to amend and/or supplement this report and visibility analysis once CAMx modeling has been completed.

Table 1-1 Summary of NO_x Four-Factor Analyses with Visibility Benefits Evaluations

List of Emission Control Measure	Factor #1 – Cost of Compliance (\$/ton of NO _x Removed)	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	Visibility Benefits	Does this Analysis Support the Installation of this Emission Control Measure?
Battery Nos. 1 and 2						
No reasonable set of NO _x emission control measures beyond what is currently installed and operated.	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not Applicable	No – There is no reasonable set of NO _x emission control measures beyond what is currently installed and operated.
Clean Coke Oven Gas Export Line and Flare						
No reasonable set of NO _x emission control measures beyond what is currently installed and operated.	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not Applicable	No – There is no reasonable set of NO _x emission control measures beyond what is currently installed and operated.
Power Station Boiler Nos. 7-12						
No reasonable set of NO _x emission control measures beyond what is currently installed and operated.	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not Applicable	No – There is no reasonable set of NO _x emission control measures beyond what is currently installed and operated.
Blast Furnaces C and D						
No reasonable set of NO _x emission control measures beyond what is currently installed and operated.	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not Applicable	No – There is no reasonable set of NO _x emission control measures beyond what is currently installed and operated.

Table 1-2 Summary of SO₂ Four-Factor Analyses with Visibility Benefits Evaluations

List of Emission Control Measure	Factor #1 – Cost of Compliance (\$/ton of SO ₂ Removed)	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	Visibility Benefits	Does this Analysis Support the Installation of this Emission Control Measure?
Battery Nos. 1 and 2						
Spray Dryer Absorber	<u>Battery No. 1</u> = \$6,300 <u>Battery No. 2</u> = \$5,300	3-4 years after SIP promulgation	<u>Energy</u> -Increased energy use to accommodate differential pressure. -Increased indirect emissions at power plant to accommodate the increased energy use. <u>Environmental</u> -Additional solid waste generation and disposal.	20-year control equipment life	Emissions reductions at BH would not improve visibility at Class I areas of interest on the most impaired days.	No –Spray Dryer Absorbers’ cost of compliance is not reasonable and it would not improve the visibility at the associated Class I areas of interest on the most impaired days.
Coke Oven Gas Desulfurization	Refer to the conclusions summarized in the Clean Coke Oven Gas Export Line row.					
Clean Coke Oven Gas Export Line						
Coke Oven Gas Desulfurization	\$4,000	3-4 years after SIP promulgation	<u>Energy</u> -Increased indirect emissions at power plant to accommodate the increased energy use. <u>Environmental</u> -Additional water usage for incremental steam demand. -Additional water draw and return from Lake Michigan for incremental cooling water demands. -Additional solid waste generation and disposal.	20-year control equipment life	Emissions reductions at BH would not improve visibility at Class I areas of interest on the most impaired days.	No – Coke Oven Gas Desulfurization’s cost of compliance is not reasonable and it would not improve the visibility at the associated Class I areas of interest on the most impaired days.
Clean Coke Oven Gas Export Line Flare						
Coke Oven Gas Desulfurization	Refer to the conclusions summarized in the Clean Coke Oven Gas Export Line row.					
Power Station Boiler Nos. 7-12						
Spray Dryer Absorber	<u>No. 7</u> = \$16,100 <u>No. 8</u> = \$21,700 <u>No. 9</u> = \$26,800 <u>No. 10</u> = \$42,000 <u>No. 11</u> = \$25,300 <u>No. 12</u> = \$20,300	3-4 years after SIP promulgation	<u>Energy</u> -Increased energy use to accommodate differential pressure. -Increased indirect emissions at power plant to accommodate the increased energy use. <u>Environmental</u> -Additional solid waste generation and disposal.	20-year control equipment life	Emissions reductions at BH would not improve visibility at Class I areas of interest on the most impaired days.	No – Spray Dryer Absorbers’ cost of compliance is not reasonable and it would not improve the visibility at the associated Class I areas of interest on the most impaired days.
Dry Sorbent Injection	<u>No. 7</u> = \$8,800 <u>No. 8</u> = \$9,900 <u>No. 9</u> = \$11,500 <u>No. 10</u> = \$16,700 <u>No. 11</u> = \$10,900 <u>No. 12</u> = \$10,000	3-4 years after SIP promulgation	<u>Energy</u> -Increased energy use to accommodate differential pressure. -Increased indirect emissions at power plant to accommodate the increased energy use. <u>Environmental</u> -Additional solid waste generation and disposal.	20-year control equipment life	Emissions reductions at BH would not improve visibility at Class I areas of interest on the most impaired days.	No – Dry Sorbent Injection’s cost of compliance is not reasonable and it would not improve the visibility at the associated Class I areas of interest on the most impaired days.
Coke Oven Gas Desulfurization	Refer to the conclusions summarized in the Clean Coke Oven Gas Export Line row.					

List of Emission Control Measure	Factor #1 – Cost of Compliance (\$/ton of SO ₂ Removed)	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	Visibility Benefits	Does this Analysis Support the Installation of this Emission Control Measure?
Blast Furnaces C and D						
No reasonable set of SO ₂ emission control measures beyond what is currently installed and operated.	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not Applicable	No – There is no reasonable set of SO ₂ emission control measures beyond what is currently installed and operated.

2 Introduction

Barr Engineering (Barr) was asked to prepare this four-factor analysis to determine the effect of BH on visibility at the applicable Class I areas, as well as determine whether additional emission control measures at identified BH units are necessary and reasonable in order to achieve reasonable progress towards national visibility goals. Section 2.1 discusses the RFI provided to BH by IDEM, pertinent regulatory background and relevant information from the 2019 RH SIP Guidance. Section 2.2 provides a description of the emission units which IDEM identified in the RFI, and Section 2.3 presents the facility-wide NO_x and SO₂ emissions data trends.

2.1 Four-Factor Analysis Regulatory Background

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 SIP development process, IDEM sent an RFI to BH on June 18, 2020. The RFI states that data from the Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring site at Bondville, Illinois indicates that sulfates and nitrates continue to be the largest contributors to visibility impairment in Indiana. The primary precursors of sulfates and nitrates are emissions of SO₂ and NO_x that react with available ammonia. The RFI stated that IDEM's source selection identified iron and steel mills as one of the source categories for analysis of emission control measures based on estimates of visibility impacts analysis. Therefore, IDEM requested that BH submit a four-factor analysis evaluating potential emission control measures, pursuant to 40 CFR 51.308(f)(2)(i), by September 30, 2020 for the emission units identified in Table 2-1.

Table 2-1 Identified Emission Units

Unit	Applicable Pollutants
Battery Nos. 1 and 2	NO _x , SO ₂
Clean Coke Oven Gas Export Line ⁽¹⁾	NO _x , SO ₂
Power Station Boiler Nos. 7-12	NO _x , SO ₂
Blast Furnaces C and D	NO _x , SO ₂

- (1) Based on IDEM's RFI referring to the flaring associated with excess coke oven gas in the event that BH does not have enough demand for the volume of coke oven gas produced in the batteries. BH reports the actual flaring emissions in the annual emission inventory submittals under the Clean Coke Oven Gas Export Line equipment identification number.

This analysis addresses 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

Additionally, this analysis evaluates the potential for visibility benefits at four Class I areas (Mammoth Cave (492 km), Mingo (568 km), Seney (511 km) and Isle Royale (708 km)) from the installation of potential emission control measures, consistent with the 2019 RH SIP Guidance.

2.1.1 Four-Factor Analysis Overview

The following sections describe the approach that was used to determine the reasonable set of emission control measures and summarize the approach for the four-factor analysis with visibility benefits evaluation as detailed in the 2019 RH SIP guidance.

2.1.1.1 Identifying Available Emission Control Measures

The identification of potentially available emission control measures for NO_x and SO₂ are discussed in Sections 3.1.1, 3.2.1, 4.1.1, 4.2.1, 5.1.1, and 5.2.1. The approach that was used to identify the emission control measures is described below.

The 2019 RH SIP Guidance states that the first step of the four-factor analysis is to identify the technically feasible control options.⁸ However, EPA recognizes that “there is no statutory or regulatory requirement to consider all technically feasible measures or any particular measures,”⁹ and states that “a range of technically feasible measures available to reduce emissions would be one way to justify a reasonable set.”¹⁰ Potentially available emission control measures include both physical and operational changes. Operational changes that would fundamentally redefine the source were not considered; for example, the analysis did not consider changes to allowable fuels or changes in raw materials.¹¹ For any technically feasible emission control measures that were identified, BH then evaluated these emission control

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 Ibid.

¹¹ Ibid, Page 30 (“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.”)

measures against the four statutory factors along with visibility benefits evaluation (used to define the reasonable set).

For the purposes of this analysis, an emission control measure was considered to be technically feasible if it has been previously installed and operated successfully on a similar source under similar physical and operating conditions. Novel emission control measures 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 on similar sources in integrated iron and steel mills (II&S mills).

For purposes of this analysis, BH evaluated only those emission control measures that have the potential to achieve an overall pollutant reduction greater than the performance of the existing systems.

The following tasks were completed to develop the reasonable set of emission control measures to be considered against the four statutory factors with visibility benefits evaluation:

1. Review the EPA's Reasonably Available Control Technology (RACT), Best Available Control Technology (BACT), and Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC), which contains "case-specific information on the 'Best Available' air pollution technologies that have been required to reduce the emission of air pollutants from stationary sources." The RBLC provided limited and dated information; the most recent pertinent information for most sources was provided in the BACT evaluation for Nucor Steel Louisiana¹² (2010 Nucor BACT). A summary of the RBLC data reviewed is provided in Appendix A.
2. Review air permits for other II&S mills to identify emission control measures and emission limits, which are being used in practice; a comparison of air permits from similar II&S mills is provided in Appendix B. Since coke oven batteries are commonly operated by third parties near II&S mills, air permits for other coke oven batteries were also reviewed.
3. Review the 2010 Nucor BACT analysis, which provides additional detail regarding specific control technologies that were evaluated for technical feasibility.
4. Select the reasonable set of emission control measures for the four-factor analysis, by process operation and by pollutant, that are most likely to be considered technically feasible; the reasonable set was selected based on the frequency of installation as identified in the RBLC, the air permits that were reviewed, and the technical discussion provided in the 2010 Nucor BACT.

In addition to the literature review, Barr interviewed process engineers from the affected areas of the BH facility to review potential emission control measures, discuss technical feasibility, and compare to the current configuration.

¹² Consolidated Environmental Management Inc – Nucor Steel Louisiana, Best Available Control Technology Analyses, March 1, 2010, PSD-LA-740.

2.1.1.2 Factor 1 – Cost of Compliance

Factor #1 considers and estimates, as needed, the capital and annual operating and maintenance (O&M) costs of the emission control measure. As directed by the 2019 RH SIP Guidance at page 31, costs of emission control measures follow the accounting principles and generic factors from the EPA Air Pollution Control Cost Manual (EPA Control Cost Manual)¹³ unless more refined site-specific estimates were available. Under this step, the annualized cost of installation and operation on a dollars per ton of pollutant removed (\$/ton) of the emission control measure, referred to as “average cost effectiveness,” is compared to a cost-effectiveness threshold that is relative to the expected visibility improvements. As stated in the 2019 RH SIP Guidance, the “balance between the cost of compliance and the visibility benefits will be an important consideration in a state’s decisions.”¹⁴

Generally, if the average cost-effectiveness is greater than the threshold and/or if there is no expected perceptible visibility improvements, 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 and the emission control measures will result in a perceptible improvement in visibility in Class I areas, 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.

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 emission control measure(s), are also 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), in tons per year (tpy), and 2) expected annual emissions performance through the installation of the additional emission control measure (controlled emissions), also in tpy.

Neither the RHR nor 2019 RH SIP Guidance provides a cost-effectiveness threshold because the analysis must consider what emission reductions are necessary to make reasonable progress. The 2019 RH SIP Guidance says that the state has the “discretion to consider the anticipated visibility benefits of an emission control measure” when making these decisions.¹⁵ For example, the installation of additional

¹³ 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.

¹⁴ US EPA, “Guidance on Regional Haze State Implementation Plans for the Second Implementation Period,” August 20, 2019, Page 37.

¹⁵ Ibid.

emission control measures at BH would not improve visibility at the associated Class I areas (as described in Section 6.3). The guidance also says “a state may be able to demonstrate, based on careful consideration of the relevant factors for its selected sources, that no additional measures are necessary to make reasonable progress in the second implementation period.”¹⁶ For example, the current visibility in associated Class I areas are either already below the 2028 URP glidepath or trending towards and expected to attain without additional emission reductions; and some facilities are already committed to additional emission reductions (as described in Section 6.2).

2.1.1.3 Factor 2 – Time Necessary for Compliance

Factor #2 considers the time needed for BH to comply with potential emission control measures. This includes the planning, designing, installing, 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 SO₂ emission control measure requires a unit outage as part of its installation, BH considers the forecasted outage schedule for the associated units in conjunction with the expected timeframe for engineering and equipment procurement following IDEM and EPA approval of the given emission control measure.

2.1.1.4 Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance

Factor #3 considers the energy and non-air environmental impacts of each 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 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 the consideration of site-specific circumstances.

2.1.1.5 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 control measures will be put in place and the date that the emission unit is anticipated to permanently cease operation. Generally, the remaining useful life of the emission unit 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 purpose of this evaluation, the remaining useful life for the units is assumed to be longer than the useful life of the additional emission control measures. Therefore, the expected useful life of the emission control measure is used to calculate the emissions reductions, amortized costs, and the resulting cost per ton removed.

¹⁶ Ibid, Page 36.

2.1.1.6 Visibility Benefits

In addition to the four statutory factors, this analysis considers the potential visibility benefits from installing additional emission control measures at the source. The 2019 RH SIP Guidance states that “visibility benefits may again be considered in that control analysis to inform the determination of whether it is reasonable to require a certain measure.”¹⁷

For the purpose of this evaluation, additional emission control measures would be inappropriate and unnecessary to make reasonable progress at the associated Class I areas if any of the following conditions are satisfied:

1. The current visibility conditions are already below (Mammoth Cave (492 km), Seney (511 km) and Isle Royale (708 km)), or trending towards and expected to attain without additional emission reductions (Mingo (568 km)), the 2028 URP,
2. The facility is not a contributor to perceptible visibility impairment on the most impaired days at the associated Class I areas, or
3. The additional emission control measure does not provide sufficient incremental visibility benefits to justify the other four factors (cost, time to implement, energy and non-air quality environmental impacts, and remaining useful life).

2.2 Affected Emission Unit Description and Existing Emission Control Measures

BH is an integrated steel mill located in Burns Harbor, Indiana. Operations include raw material handling, coke plant operations, ironmaking, steelmaking, and manufacturing of hot rolled, cold rolled, and hot-dipped galvanized sheet products. The three emission unit groups addressed in IDEM’s RFI are described below.

2.2.1 Battery Nos. 1 and 2, Clean Coke Oven Gas Export Line and Flare

Cokemaking involves heating of coal in the absence of air resulting in the separation of non-carbon elements of the coal product (i.e. coke) for use in blast furnaces. Battery No. 1 fires coke oven gas and blast furnace gas, while Battery No. 2 fires coke oven gas to heat the coal reduce volatile organic compounds and water, producing a destructively distilled material. The byproducts (tar, ammonia liquor, etc.), including coke oven gas, are collected in the by-products plant.

Battery Nos. 1 and 2 generate NO_x and SO₂ emissions from blast furnace gas and coke oven gas underfire combustion. Blast furnace gas is considered a low-NO_x fuel because it has a lower heating value compared to natural gas (approximately 10% of the heating value) which creates a lower flame temperature and generates significantly less thermal NO_x. Therefore, the use of blast furnace gas in

¹⁷ US EPA, “Guidance on Regional Haze State Implementation Plans for the Second Implementation Period,” August 20, 2019, Page 34.

Battery No. 1 is an existing NO_x emission control measure. Battery No. 2 is designed with staged combustion. This is a NO_x emission control measure that decreases thermal NO_x formation by reducing peak flame temperatures.

The coke oven gas produced in Battery Nos. 1 and 2 is a source of energy rich organic molecules. The clean coke oven gas export line is the fuel distribution line that delivers coke oven gas to other departments/processes at BH that fire coke oven gas¹⁸. Before export, the gas is scrubbed of particulate matter (PM). The export line is equipped with a flare in the event BH does not have enough demand for the volume of coke oven gas produced in the batteries.

NO_x and SO₂ emissions are generated at the flare stack for the portion of coke oven gas that is not redistributed throughout the plant.

2.2.2 Power Station Boiler Nos. 7-12

The Power Station Boiler Nos. 7-12 produce utility steam for use throughout the BH facility. The boilers primarily fire coke oven gas, natural gas, and blast furnace gas, but are also permitted to fire coal tar and fuel oil.

The Power Station Boiler Nos. 7-12 generate NO_x emissions from fuel combustion. Blast furnace gas is considered a low-NO_x fuel because it has a lower heating value compared to natural gas (approximately 10% of the heating value) which creates a lower flame temperature and generates significantly less thermal NO_x. The Power Station Boiler Nos. 7-12 utilize low-NO_x fuel and good combustion practices as NO_x emission control measures.

The Power Station Boiler Nos. 7-12 generate SO₂ emissions from natural gas and blast furnace gas combustion. Natural gas and blast furnace gas are considered low-sulfur fuels when compared to other solid and liquid fuels, and are utilized as an SO₂ emission control measure.

2.2.3 Blast Furnaces C and D

Blast Furnaces C and D combine coke, limestone, sinter, iron ore pellets, and other iron sources with high heat to produce molten iron. Hot air must be injected into the blast furnace to ignite the added coke. This hot air is produced in the blast furnace stoves, which fire blast furnace gas, coke oven gas, and natural gas to heat fresh air for injection. Blast furnace gas is the partially combusted, CO-rich gas that is produced within the blast furnace itself. This gas has a low heating value and is cleaned for PM via the integrated scrubbing system prior to combustion as a fuel source to offset purchased fuels and improve energy efficiency.

¹⁸ Downstream coke oven gas users include: Battery No. 1 Underfire, Battery No. 2 Underfire, C Blast Furnace Stoves, D Blast Furnace Stoves, 160 Inch Plate Mill Continuous Reheat Furnaces Nos. 1 and 2, 160 Inch Plate Mill In and Out Reheat Furnace Nos. 5-7, 110 inch Plate Mill Slab Reheat Furnaces No. 1 and 2, Hot Strip Mills Reheat Furnaces No. 1-3, Power Station Boilers No. 7-12, Clean Coke Oven Gas Export Line Flare, and Slab Mill Soaking Pits.

Once the molten iron is produced, the furnace is tapped and the molten iron flows through a series of troughs into refractory lined bottle cars for rail transfer to the steel shop(s).

The Blast Furnaces C and D Stoves resulting NO_x emissions are generated from primarily firing blast furnace gas, coke oven gas, and natural gas enrichment to raise the fuel's heating value enough to hit furnace dome temperature by the end of the heating cycles. The heat is then transferred out of the stove to preheat fresh air (cold blast) for recovering heat back to the furnace through "hot blast" injection. Blast furnace gas is considered a low-NO_x fuel because it has a lower heating value compared to natural gas (approximately 10% of the heating value) which creates a lower flame temperature and generates significantly less thermal NO_x. Therefore, the use of blast furnace gas in the Blast Furnaces C and D is an existing NO_x emission control measure.

The Blast Furnaces C and D Stoves generate SO₂ emissions through oxidation of sulfur compounds present in the fuel (blast furnace gas, natural gas, and coke oven gas). Blast furnace gas and natural gas are considered low-sulfur fuels, compared to other solid and liquid fuels, and are utilized as SO₂ emission control measures.

The NO_x emissions from the Blast Furnaces C and D Casthouses are not significant (66.94 ton NO_x per year in 2018). NO_x emissions may be generated during the casting process and are a result of reactions of nitrogen in ambient air.

The Blast Furnaces C and D Casthouses' molten iron and slag streams contain sulfur compounds that oxidize to form SO₂ upon contact with ambient air during the casting process. Casting emissions are collected and routed to one of two casthouse baghouses for particulate control. Emissions from slag runners and pits outside of the casthouse are also fugitive-in-nature (i.e., not emitted from a stack).

The Blast Furnaces C and D Flares produce NO_x and SO₂ due to the combustion of blast furnace waste gas and natural gas pilots. Blast furnace gas is a low-NO_x fuel and is utilized as an existing NO_x emission control measure. Blast furnace gas and natural gas are considered low-sulfur fuels and are SO₂ emission control measures.

2.3 Facility-wide NO_x and SO₂ Emission Trends

The goal of the RHR is to improve the visibility at Class I areas of interest through visibility-impairing pollutant emission reductions. Independent of any RHR requirements, BH has achieved substantial facility-wide NO_x and SO₂ emission reductions in the recent years as a result of extensive projects, including the permanent idling of thirty-six (36) coke oven gas and/or blast furnace gas fired Slab Mill Soaking Pits and 160 inch Plate Mill I & O Furnace No. 8. Figure 2-1 presents the facility-wide NO_x and SO₂ emissions from 2005 to 2019. BH has already reduced NO_x and SO₂ emissions by 18% from 2005 (2005 = 25,023 tons/year NO_x and SO₂, 2019 = 20,415 tons/year NO_x and SO₂) and, therefore, additional emission control measures are not necessary to achieve reasonable progress when considered in conjunction with the current visibility trends (see Section 6.1) and the lack of visibility impacts at the associated Class I areas from BH (see Section 6.3). Note, the 2009 and 2010 emissions reflect an economic downturn that resulted in reduced production rates.

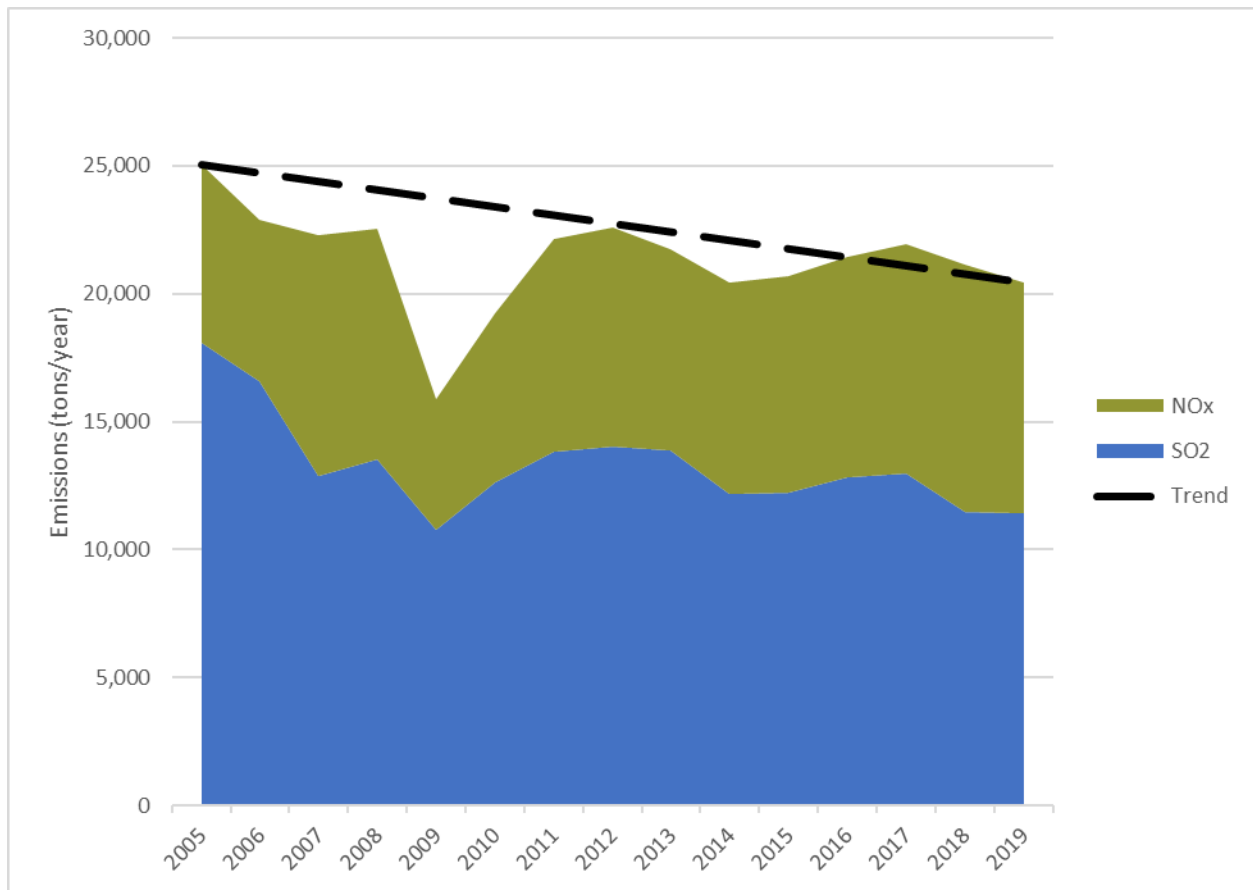


Figure 2-1 Facility-wide NO_x and SO₂ Emissions from 2005 to 2019

3 Battery Nos. 1 and 2, Clean Coke Oven Gas Export Line and Flare

The following sections describe the four-factor analyses with visibility benefits evaluations for NO_x and SO₂ emission control measures for Battery Nos. 1 and 2, the Clean Coke Oven Gas Export Line, and Clean Coke Oven Gas Export Line Flare.

3.1 Four-Factor Analysis – NO_x

The following sections describe the analysis for determining the reasonable set of NO_x emission control measures (Section 3.1.1), the four-factor analysis with visibility benefits evaluation (Sections 3.1.3 through 3.1.7), and the proposed emission control measures (Section 3.1.8) for Battery Nos. 1 and 2, the Clean Coke Oven Gas Export Line, and Clean Coke Oven Gas Export Line Flare.

3.1.1 NO_x Emission Control Measures

3.1.1.1 Battery Nos. 1 and 2

The RBLC search (summarized in Appendix A) and search of air permits for II&S mills and similar sources (Appendix B) for Coke Oven Battery NO_x emission control measures identified the use of staged combustion at some sources. Since coke oven batteries are commonly operated by third parties near II&S mills, air permits from other similar sources were reviewed to identify NO_x emission control measures. As described in Section 2.2.1, Battery No. 1 already utilizes low-NO_x fuel combustion (blast furnace gas) and Battery No. 2 has staged combustion as existing NO_x emission control measures.

The RBLC search (Appendix A) listed three instances of staged combustion for coke oven batteries (Middletown Coke Company (RBLCID = OH-0332), EES Coke Battery, LLC (RBLCID = MI-0415) and Nucor St. James (RBLCID = LA-0239)).

By-product coke oven batteries are inherently different than non-recovery coke oven battery by design. It is not technically feasible to install staged combustion on Battery No. 1 without a battery rebuild. The BH By-Products Coke Oven Battery heating flue design inside the oven walls is part of the battery refractory oven wall construction. The heating of Battery No. 1 is performed with 2,656 individual heating flues. Therefore, the battery heating system is not a single point combustion source. The heating flue cannot be changed without tearing down the refractory oven walls and rebuilding each of them with a different design. A redesign of this magnitude would entail a rebuild of the entire coke oven battery, which for a 6-meter, 82 oven battery would cost hundreds of millions of dollars. Additionally, EPA stated the following in the New Source Review Workshop Manual¹⁹:

¹⁹ US EPA, "New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting," Page B.13, October 1990

“Historically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives.”

Due to the thousands of combustion units in the battery and the design of each combustion unit being an integral part of the individual oven wall design, the installation of staged combustion on an existing by-products coke oven battery is not technically feasible. Therefore, staged combustion was excluded from the reasonable set for Battery No. 1.

Since it is not technically feasible to install staged combustion on Battery No. 1 and Battery No. 2 is already designed with staged combustion, there are no additional NO_x emission control measures based on the emission control measures described in the RBLC (Appendix A) and air permits for II&S mills (Appendix B). As such, Battery Nos. 1 and 2 have no reasonable set of NO_x emission control measures beyond what is currently installed and operated for these emission units.

3.1.1.2 Clean Coke Oven Gas Export Line

3.1.1.2.1 Clean Coke Oven Gas Export Line Downstream Emission Units

The NO_x emissions generated from coke oven gas fired in downstream emission units¹⁸ are dependent on the burner-specific characteristics (e.g., flame temperature, O₂ levels, etc.). Accordingly, it is not appropriate to evaluate NO_x emission control measures on the Clean Coke Oven Gas Export Line. As such, the Clean Coke Oven Gas Export Line has no reasonable set of NO_x emission control measures.

3.1.1.2.2 Clean Coke Oven Gas Export Line Flare

As stated in Section 2.2.1, coke oven gas is routed to a bleeder flare in the event BH does not have enough demand for the volume of coke oven gas produced in the batteries. The RBLC search (summarized in Appendix A) and search of air permits for II&S mills and similar sources (Appendix B) for Coke Oven Battery Flares did not identify any NO_x emission control measures.

There are no additional NO_x emission control measures based on the emission control measures described in the RBLC (Appendix A) and air permits for II&S mills and similar sources (Appendix B). As such, the Clean Coke Oven Gas Export Line Flare has no reasonable set of NO_x emission control measures beyond what is currently installed and operated for this emission unit.

3.1.2 Baseline Emission Rates

Since the four-factor analysis concluded Battery Nos. 1 and 2, the Clean Coke Oven Gas Export Line, and Clean Coke Oven Gas Export Line Flare have no reasonable set of NO_x emission control measures beyond what is currently installed and operated for these emission units, it is not necessary to represent a projected 2028 emissions scenario.

3.1.3 Factor 1 – Cost of Compliance

Since the four-factor analysis concluded Battery Nos. 1 and 2, the Clean Coke Oven Gas Export Line, and Clean Coke Oven Gas Export Line Flare have no reasonable set of NO_x emission control measures beyond

what is currently installed and operated for these emission units, it is not appropriate to estimate the cost of compliance for additional NO_x emission control measures.

3.1.4 Factor 2 – Time Necessary for Compliance

Since the four-factor analysis concluded Battery Nos. 1 and 2, the Clean Coke Oven Gas Export Line, and Clean Coke Oven Gas Export Line Flare have no reasonable set of NO_x emission control measures beyond what is currently installed and operated for these emission units, it is not appropriate to describe the time that is necessary to achieve compliance for additional NO_x emission control measures.

3.1.5 Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance

Since the four-factor analysis concluded Battery Nos. 1 and 2, the Clean Coke Oven Gas Export Line, and Clean Coke Oven Gas Export Line Flare have no reasonable set of NO_x emission control measures beyond what is currently installed and operated for these emission units, it is not appropriate to describe the energy and non-air quality environmental impacts for additional NO_x emission control measures.

3.1.6 Factor 4 – Remaining Useful Life of the Source

Since the four-factor analysis concluded Battery Nos. 1 and 2, the Clean Coke Oven Gas Export Line, and Clean Coke Oven Gas Export Line Flare have no reasonable set of NO_x emission control measures beyond what is currently installed and operated for these emission units, it is not appropriate to describe the remaining useful life of the source.

3.1.7 Visibility Benefits

Since the four-factor analysis concluded Battery Nos. 1 and 2, the Clean Coke Oven Gas Export Line, and Clean Coke Oven Gas Export Line Flare have no reasonable set of NO_x emission control measures beyond what is currently installed and operated for these emission units, it is not appropriate to describe the potential visibility benefits for additional NO_x emission control measures.

3.1.8 Proposed NO_x Emission Control Measures

Based on the four-factor analysis, installation of additional NO_x emission control measures at Battery Nos. 1 and 2, the Clean Coke Oven Gas Export Line, and Clean Coke Oven Gas Export Line Flare beyond those described in Section 2.2.1 are not required to make reasonable progress. As such, this analysis proposes to maintain the existing NO_x emission control measures.

3.2 Four-Factor Analysis – SO₂

The following sections describe the analysis for determining the reasonable set of SO₂ emission control measures (Section 3.2.1), the 2028 projected baseline SO₂ emission rates (Section 3.2.2), the four-factor analysis with visibility benefits evaluation (Sections 3.2.3 through 3.2.7), and the proposed emission control measures (Section 3.2.8) for Battery Nos. 1 and 2, the Clean Coke Oven Gas Export Line, and Clean Coke Oven Gas Export Line Flare.

3.2.1 SO₂ Emission Control Measures

3.2.1.1 Battery Nos. 1 and 2

The RBLC search (summarized in Appendix A) and search of air permits for II&S mills and similar sources (Appendix B) for Coke Oven Battery SO₂ emission control measures identified the use of wet venturi scrubbers, spray dryer absorbers (also referred to as lime spray dryers), and/or desulfurization plants at some sources. Since coke oven batteries are commonly operated by third parties near II&S mills, air permits from other similar sources were reviewed to identify SO₂ emission control measures.

Wet scrubbers²⁰ can offer SO₂ control performance levels that are generally consistent with spray dryer absorbers⁴. However, wet scrubbers produce substantial amounts of sulfate-impacted wastewater which requires additional wastewater treatment processes at the facility. As such, wet scrubbers are excluded from the reasonable set of SO₂ emission control measures for the Battery Nos. 1 and 2.

BH identified coke oven gas treatment through the installation of a desulfurization plant⁵ to be part of the reasonable set of SO₂ emission control measures for further evaluation. Since a desulfurization plant affects all of the downstream coke oven gas consumers, it is addressed separately in Section 3.1.1.2.

BH identified installation of spray dryer absorbers or a desulfurization plant (refer to Section 3.1.1.2) to be part of the reasonable set of SO₂ emission control measures for further evaluation. The spray dryer absorbers would require the installation of new PM baghouses to collect the spent sorbent.

Installation of spray dryer absorbers or a desulfurization plant for Battery Nos. 1 and 2 is evaluated as an SO₂ emission control measure in Sections 3.2.3 through 3.2.7.

3.2.1.2 Clean Coke Oven Gas Export Line

3.2.1.2.1 Clean Coke Oven Gas Export Line Downstream Emission Units

As noted above, certain II&S mills and similar sources have onsite coke oven gas desulfurization plants as an SO₂ emission control measure.

BH identified installation of coke oven gas desulfurization to be part of the reasonable set of SO₂ emission control measures for the Clean Coke Oven Gas Export Line for further evaluation.

Coke oven gas desulfurization for the Clean Coke Oven Gas Export Line¹⁸ is evaluated as a SO₂ emission control measure in Sections 3.2.3 through 3.2.7.

²⁰ Wet scrubbing, when applied to remove SO₂, is generally termed flue-gas desulfurization (FGD). FGD utilizes gas absorption technology, the selective transfer of materials from a gas to a contacting liquid, to remove SO₂ in the waste gas. Crushed limestone, lime, or caustic are used as scrubbing agents. Typical high-efficiency SO₂-control wet scrubbers are packed-bed spray towers using a caustic scrubbing solution.

3.2.1.2.2 Clean Coke Oven Gas Export Line Flare

As stated in Section 2.2.1, coke oven gas is routed to a flare in the event BH does not have enough demand for the volume of coke oven gas produced in the batteries. The RBLC search (summarized in Appendix A) and search of air permits for I&S mills and similar sources (Appendix B) for Coke Oven Battery Flares SO₂ emission control measures identified the use of coke oven gas desulfurization.

BH identified coke oven gas treatment through the installation of a desulfurization plant to be part of the reasonable set of SO₂ emission control measures for further evaluation. Since a desulfurization plant affects all of the downstream coke oven gas consumers, including the Clean Coke Oven Gas Export Line Flare, it is addressed separately in Section 3.1.1.2.

Coke oven gas desulfurization for the Clean Coke Oven Gas Export Line Flare is evaluated as a SO₂ emission control measure in Sections 3.2.3 through 3.2.7.

3.2.2 Baseline Emission Rates

The four-factor analysis requires the establishment of a baseline scenario for evaluating a potential emission control measure. At 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 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. For the purpose of the four-factor analysis, BH considered the representative historical period to be 2018 to represent projected 2028 baseline emissions. The estimated 2028 baseline SO₂ emissions are shown in Table 3-1.

Table 3-1 Estimated 2028 Baseline SO₂ Emissions for the Identified Emission Units

Unit	2028 Projected Baseline Coke Oven Gas Throughput Assumption (MMscf/year)	Coke Oven Gas SO ₂ Emission Factor ⁽¹⁾ (lb/MMscf)	2028 Projected Baseline Blast Furnace Gas Throughput Assumption (MMscf/year)	Blast Furnace Gas SO ₂ Emission Factor ⁽²⁾ (lb/MMscf)	Estimated 2028 SO ₂ Emissions (tons/year)
Coke Oven Battery No. 1 Underfire	5,262	604	4,235	13.11	1,617
Coke Oven Battery No. 2 Underfire	6,138	604	-	-	1,854
Clean Coke Oven Gas Export Line ⁽³⁾	155	604	-	-	47

(1) Emission factor is based on No. 2 Battery semi-annual stack testing.

(2) Emission factor is based on stack testing completed for annual emission fees.

(3) Downstream coke oven gas users include: Battery No. 1 Underfire, Battery No. 2 Underfire, C Blast Furnace Stoves, D Blast Furnace Stoves, 160 Inch Plate Mill Continuous Reheat Furnaces Nos. 1 and 2, 160 Inch Plate Mill In and Out Reheat Furnace Nos. 5-7, 110 inch Plate Mill Slab Reheat Furnaces No. 1 and 2, Hot Strip Mills Reheat Furnaces No. 1-3, Power Station Boilers No. 7-12, Clean Coke Oven Gas Export Line Flare, and Slab Mill Soaking Pits.

3.2.3 Factor 1 – Cost of Compliance

BH completed cost estimates for installation of a spray dryer absorber on Battery Nos. 1 and 2 as well as for coke oven gas desulfurization on the Clean Coke Oven Gas Export Line. Cost summary spreadsheets for the SO₂ emission control measures are provided in Appendix C.1, C.2, and C.3.

The cost-effectiveness analysis compares the annualized cost of the emission control measure 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 and consistent with the typical approach described in the EPA Control Cost Manual²¹, a 20-year life (before new and extensive capital is needed to maintain and repair the equipment) at 5.5% interest is assumed in annualizing capital costs.

The resulting cost-effectiveness calculations are summarized in Table 3-2.

²¹ 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

Table 3-2 SO₂ Control Cost Summary, per Unit Basis

Emission Unit	Additional Emission Control Measure	Total Annualized Costs (\$/yr)	Annual Emissions Reduction (tpy)	Pollution Control Cost Effectiveness (\$/ton)
Battery No. 1	Spray Dryer Absorber	\$9,527,000	1,507	\$6,300
Battery No. 2	Spray Dryer Absorber	\$8,783,000	1,668	\$5,300
Clean Coke Oven Gas Export Line	Coke Oven Gas Desulfurization	\$27,854,000	6,997	\$4,000

The cost-effectiveness values for all of the SO₂ emission control measures are not justifiable because the emission control measures would not result in visibility improvements at the associated Class I areas. The visibility impacts analysis completed to date indicates that BH is not a contributor to perceptible visibility impairment to the Class I areas on the most impaired days, thus any installation of additional emission control measures at BH will not provide perceptible visibility benefits in these Class I areas (see Section 6.3). Further analysis through CAMx modeling that is underway is anticipated to show that BH does not have a perceptible visibility impact on these Class I areas. Therefore, the costs for the additional SO₂ emission control measure options are not reasonable.

Sections 3.2.4 through 3.2.7 provide a summary of the remaining factors evaluated for the SO₂ emission control measures, understanding that these projects represent substantial costs that are not justified on a cost per ton or absolute cost basis.

3.2.4 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 IDEM to modify BH's Title V operating permit to allow construction to commence, then to implement the project necessary to meet the SIP limit for the emission control measure, including capital funding, construction, tie-in to the process, commissioning, and performance testing.

The technologies would require significant resources and time of at least three to four years to engineer, permit, and install the equipment. However, prior to beginning this process, the SIP must first be submitted by IDEM in July 2021 and then approved by EPA, which is anticipated to occur within 12 to 18 months after submittal (approximately 2022 to 2023). Thus, the installation date would occur between 2024 and 2026. The 5-year average visibility impairment on the most impaired days at the associated Class I areas of interest is already below, or trending towards and expected to attain without additional emission reductions, the 2028 URP. Thus, weighing in the time necessary for compliance to the cost against the status and timeline for achieving reasonable progress goals further supports the conclusion that the substantial costs that are not justified.

3.2.5 Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance

The spray dryer absorber on the Battery Nos. 1 and 2 would increase energy usage due to the higher pressure drop across the absorber vessels and new downstream baghouses, material preparation such as grinding reagents, additional material handling equipment such as pumps and blowers, and steam requirements. The cost of energy required to operate the spray dryer absorbers have been included in the cost analyses found in Appendix C.1 and C.2.

The spray dryer absorbers would generate additional solid waste that would require disposal in permitted landfills.

Coke oven gas desulfurization for the Clean Coke Oven Gas Export Line will involve the installation of sulfur recovery and Claus off-gas treating units (SRU/SCOT), which will require additional electricity, steam, cooling water, and biological wastewater treatment. The increased electrical usage by the plant will result in associated increases in indirect (secondary) emissions from nearby power stations. The additional steam will require additional water usage and additional cooling water demand will require additional water draw and return from Lake Michigan. The desulfurization plant will generate a waste stream requiring disposal from the reclaimer.

3.2.6 Factor 4 – Remaining Useful Life of the Source

Because BH is assumed to continue operations for the foreseeable future, the useful life of the individual emission control measures (assumed 20-year life, per Section 2.1.1.5) is used to calculate emission reductions, amortized costs and cost-effectiveness on a dollar per ton basis.

3.2.7 Visibility Benefits

Independent of the four-factor analysis, the installation of a spray dryer absorber on Battery Nos. 1 and 2 and coke oven gas desulfurization for the Clean Coke Oven Gas Export Line are not appropriate and are unnecessary because:

1. The 5-year average visibility impairment on the most impaired days at the associated Class I areas of interest is already below (Mammoth Cave (492 km), Seney (511 km) and Isle Royale (708 km)), or trending towards and expected to attain without additional emission reductions (Mingo (568 km)), the 2028 URP (see Section 6.1),
2. The visibility impacts analysis completed to date indicates that BH is not a contributor to perceptible visibility impairment to the Class I areas on the most impaired days (see Section 6.3) and is not expected to have a perceptible contribution to visibility impacts based on CAMx modeling that is underway, and
3. Installation of a spray dryer absorber on Battery Nos. 1 and 2 and coke oven gas desulfurization for the Clean Coke Oven Gas Export Line do not justify the associated costs, as described in Section 3.2.3, because the emission control measures are neither necessary to, nor expected to, provide perceptible visibility benefits (see Section 6.3).

3.2.8 Proposed SO₂ Emission Control Measures

Based on the four-factor analysis with visibility benefits evaluation, installation of additional SO₂ emission control measures at Battery Nos. 1 and 2, the Clean Coke Oven Gas Export Line, and Clean Coke Oven Gas Export Line Flare beyond those described in Section 2.2.1 are not required to make reasonable progress in reducing SO₂ emissions. As such, this analysis proposes to maintain the existing SO₂ emission control measures.

4 Power Station Boiler Nos. 7-12

The following sections describe the four-factor analyses with visibility benefits evaluations for NO_x and SO₂ emission control measures for the Power Station Boiler Nos. 7-12.

4.1 Four-Factor Analysis - NO_x

The following sections describe the analysis for determining the reasonable set of NO_x emission control measures (Section 4.1.1), the four-factor analysis with visibility benefits evaluation (Sections 4.1.3 through 4.1.7), and the proposed emission control measures (Section 4.1.8) for the Power Station Boiler Nos. 7-12.

4.1.1 NO_x Emission Control Measures

The RBLC search (summarized in Appendix A) and search of air permits for II&S mills and similar sources (Appendix B) for Boilers NO_x emission control measures identified the use of low-NO_x fuel, Selective Catalytic Reduction (SCR)²², Low NO_x Burners (LNB)²³, and ULNB at some sources. As described in Section 2.2.2, the Power Station Boiler Nos. 7-12 already utilize low-NO_x fuel combustion (blast furnace gas) and good combustion practices as existing NO_x emission control measures.

The RBLC search (Appendix A) listed many references to the installation of SCR, LNB, and ULNB for natural gas only-fired boilers. The Power Station Boiler Nos. 7-12 are not directly comparable to boilers that strictly fire natural gas because the Power Station Boiler Nos. 7-12 fire a combination of blast furnace gas (a low-NO_x fuel), coke oven gas, and natural gas.

SCR is excluded from the reasonable set because it has not been installed and successfully operated on a similar source under similar physical and operating conditions (i.e., firing blast furnace gas as a primary fuel source).

Although LNB/ULNB have been installed and operated on natural gas-fired boilers, the design of Power Station Boiler Nos. 7-12 prohibits the installation of LNB/ULNB. The primary reason is that the boilers are relatively "short" in height as they were designed primarily for combustion of blast furnace gas and coke oven gas with some supplemental natural gas and fuel oil. Thus, the distances from the burners to the superheat tube sections of the boilers are not adequate and LNB/ULNB's elongated flames would result in flame impingement (flame touching or surrounding the tubes or supports). Flame impingement would compromise the boilers in several ways, including: reliability because flame impingement may cause ruptured tubes requiring unpredictable and extended shutdowns; safety as ruptured tube events

²² SCR reduces NO_x emissions with ammonia or urea injection in the presence of a catalyst.

²³ LNB reduces NO_x emissions by decreasing the burner flame temperature from staging either the combustion air or fuel injection rates into the burner.

represents a significant danger to operators and the equipment; operational efficiency since flame impingement results in tube corrosion; and increased maintenance.

To prevent flame impingement, the boilers' fireboxes would require substantial redesign and the current location at the site prohibits the associated modifications. In addition, the necessary changes would require fundamentally redesigning the boiler (i.e., firebox, burner, tubes) and surrounding facilities, which is not appropriate for this analysis (refer to Section 2.1.1.1 for a description of EPA's guidance when selecting the reasonable set of emission control measures). Additionally, EPA stated the following in the New Source Review Workshop Manual¹⁹:

"Historically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives."

As such, the installation of LNB/ULNBs on the Power Station Boilers No. 7-12 is not technically feasible, and is excluded from further analysis.

Since it is not technically feasible to install LNB/ULNB on Power Station Boilers No. 7-12, there are no additional NO_x emission control measures based on the emission control measures described in the RBLC (Appendix A) and air permits for II&S mills (Appendix B). As such, Battery Nos. 1 and 2 have no reasonable set of NO_x emission control measures beyond what is currently installed and operated for these emission units.

4.1.2 Baseline Emission Rates

Since the four-factor analysis concluded Power Station Boiler Nos. 7-12 have no reasonable set of NO_x emission control measures beyond what is currently installed and operated for these emission units, it is not necessary to represent a projected 2028 emissions scenario.

4.1.3 Factor 1 – Cost of Compliance

Since the four-factor analysis concluded Power Station Boiler Nos. 7-12 have no reasonable set of NO_x emission control measures beyond what is currently installed and operated for these emission units, it is not appropriate to estimate the cost of compliance for additional NO_x emission control measures.

4.1.4 Factor 2 – Time Necessary for Compliance

Since the four-factor analysis concluded Power Station Boiler Nos. 7-12 have no reasonable set of NO_x emission control measures beyond what is currently installed and operated for these emission units, it is not appropriate to describe the time that is necessary to achieve compliance for additional NO_x emission control measures.

4.1.5 Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance

Since the four-factor analysis concluded Power Station Boiler Nos. 7-12 have no reasonable set of NO_x emission control measures beyond what is currently installed and operated for these emission units, it is

not appropriate to describe the energy and non-air quality environmental impacts for additional NO_x emission control measures.

4.1.6 Factor 4 – Remaining Useful Life of the Source

Since the four-factor analysis concluded Power Station Boiler Nos. 7-12 have no reasonable set of NO_x emission control measures beyond what is currently installed and operated for these emission units, it is not appropriate to describe the remaining useful life of the source.

4.1.7 Visibility Benefits

Since the four-factor analysis concluded Power Station Boiler Nos. 7-12 have no reasonable set of NO_x emission control measures beyond what is currently installed and operated for these emission units, it is not appropriate to describe the potential visibility benefits for additional NO_x emission control measures.

4.1.8 Proposed NO_x Emission Control Measures

Based on the four-factor analysis, installation of additional NO_x emission control measures at the Power Station Boiler Nos. 7-12 beyond those described in Section 2.2.2 are not required to make reasonable progress in reducing NO_x emissions. As such, this analysis proposes to maintain the existing NO_x emission control measures.

4.2 Four-Factor Analysis - SO₂

The following sections describe the analysis for determining the reasonable set of SO₂ emission control measures (Section 4.2.1), the 2028 projected baseline SO₂ emission rates (Section 4.2.2), the four-factor analysis with visibility benefits evaluation (Sections 4.2.3 through 4.2.7), and the proposed emission control measures (Section 4.2.8) for the Power Station Boiler Nos. 7-12.

4.2.1 SO₂ Emission Control Measures

The RBLC search (summarized in Appendix A) and search of air permits for II&S mills and similar sources (Appendix B) for Boilers SO₂ emission control measures identified the use of low-sulfur fuels at some sources. As described in Section 2.2.2, the Power Station Boiler Nos. 7-12 already utilize low-sulfur fuel combustion (natural gas and blast furnace gas) as an existing SO₂ emission control measure.

It is not appropriate to compare SO₂ emission control measures at other II&S mills for similar units because the Power Station Boiler Nos. 7-12 fire coke oven gas and coke oven gas is not a low-sulfur fuel²⁴ (e.g., natural gas, blast furnace gas). Wet scrubbers, spray dryer absorbers, and dry sorbent injection⁷ are common add-on SO₂ emission control measures applied to boilers in other industries.

Wet scrubbers can offer SO₂ control performance levels that are generally consistent with spray dryer absorbers and dry sorbent injection. However, wet scrubbers produce substantial amounts of sulfate-

²⁴ Desulfurized coke oven gas is a low-sulfur fuel which is addressed as coke oven gas desulfurization in Section 3.2.

impacted wastewater which requires additional wastewater treatment processes at the facility. As such, wet scrubbers are excluded from the reasonable set of SO₂ emission control measures for the Power Station Boiler Nos. 7-12.

BH identified coke oven gas treatment through the installation of a desulfurization plant to be part of the reasonable set of SO₂ emission control measures for further evaluation. Since a coke oven gas desulfurization plant affects all of the downstream coke oven gas consumers, including the Power Station Boiler Nos. 7-12, it is addressed separately in Section 3.1.1.2.1. For the reasons stated in that Section, installation of a desulfurization plant was determined not to be reasonable or justified.

BH identified spray dryer absorbers, dry sorbent injection, and a coke oven gas desulfurization plant to be part of the reasonable set of SO₂ emission control measures for further evaluation. Spray dryer absorbers and dry sorbent injection are evaluated in Sections 4.2.3 through 4.2.7. The spray dryer absorbers and dry sorbent injection would require the installation of new PM baghouses to collect the spent sorbent. Coke oven gas desulfurization is evaluated in Sections 3.2.3 through 3.2.7 and therefore is not necessary to be readdressed in the following sections.

4.2.2 Baseline Emission Rates

The four-factor analysis requires the establishment of a baseline scenario for evaluating a potential emission control measure. At 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 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. For the purpose of the

four-factor analysis, BH represented the projected 2028 baseline emissions based on the 2018 actual emissions, as shown in Table 4-1.

Table 4-1 Estimated 2028 Baseline SO₂ Emissions for the Identified Emission Units

Unit	2028 Projected Baseline Coke Oven Gas Throughput Assumption (MMscf/year)	Coke Oven Gas SO ₂ Emission Factor ⁽¹⁾ (lb/MMscf)	2028 Projected Baseline Blast Furnace Gas Throughput Assumption (MMscf/year)	Blast Furnace Gas SO ₂ Emission Factor ⁽²⁾ (lb/MMscf)	2028 Projected Baseline Natural Gas Throughput Assumption (MMscf/year)	Natural Gas SO ₂ Emission Factor ⁽³⁾ (lb/MMscf)	Estimated 2028 SO ₂ Emissions (tons/year)
Power Station Boiler #7	2,592	604.0	17,975	13.1	397	0.6	901
Power Station Boiler #8	2,142	604.0	528	13.1	2,236	0.6	651
Power Station Boiler #9	1,582	604.0	7,032	13.1	1,380	0.6	524
Power Station Boiler #10	1,012	604.0	4,201	13.1	1,502	0.6	334
Power Station Boiler #11	1,802	604.0	1,469	13.1	1,373	0.6	554
Power Station Boiler #12	2,251	604.0	3,432	13.1	1,323	0.6	703

(1) Emission factor is based on No. 2 Battery semi-annual stack testing.

(2) Emission factor is based on stack testing completed for annual emission fees.

(3) Emission factor is from AP-42 Section 1.4; Table 1.4-2; July 1998

4.2.3 Factor 1 – Cost of Compliance

BH completed cost estimates for spray dryer absorbers and dry sorbent injection on the Power Station Boiler Nos. 7-12. Cost summary spreadsheets for the SO₂ emission control measures are provided in Appendix C.4 through C.9.

The cost-effectiveness analysis compares the annualized cost of the emission control measure 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 and consistent with the typical approach described in

the EPA Control Cost Manual²⁵, a 20-year life (before new and extensive capital is needed to maintain and repair the equipment) at 5.5% interest is assumed in annualizing capital costs.

The resulting cost-effectiveness calculations are summarized in Table 4-2.

Table 4-2 SO₂ Control Cost Summary, per Unit Basis

Emission Unit	Additional Emission Control Measure	Total Annualized Costs (\$/yr)	Annual Emissions Reduction (tpy)	Pollution Control Cost Effectiveness (\$/ton)
Power Station Boiler #7	Spray Dryer Absorber	\$13,025,000	811	\$16,100
Power Station Boiler #7	Dry Sorbent Injection	\$5,555,000	631	\$8,800
Power Station Boiler #8	Spray Dryer Absorber	\$12,700,000	586	\$21,700
Power Station Boiler #8	Dry Sorbent Injection	\$4,534,000	456	\$9,900
Power Station Boiler #9	Spray Dryer Absorber	\$12,634,000	472	\$26,800
Power Station Boiler #9	Dry Sorbent Injection	\$4,224,000	367	\$11,500
Power Station Boiler #10	Spray Dryer Absorber	\$12,600,000	300	\$42,000
Power Station Boiler #10	Dry Sorbent Injection	\$3,898,000	234	\$16,700
Power Station Boiler #11	Spray Dryer Absorber	\$12,622,000	499	\$25,300
Power Station Boiler #11	Dry Sorbent Injection	\$4,235,000	388	\$10,900
Power Station Boiler #12	Spray Dryer Absorber	\$12,856,000	633	\$20,300
Power Station Boiler #12	Dry Sorbent Injection	\$4,941,000	492	\$10,000

The cost-effectiveness values for all of the SO₂ emission control measures are not justifiable because the emission control measures would not result in visibility improvements at the associated Class I areas, Section 2.1.1.2. The visibility impacts analysis completed to date indicates that BH is not a contributor to perceptible visibility impairment to the Class I areas on the most impaired days, thus any installation of additional emission control measures at BH will not provide perceptible visibility benefits in these Class I areas (see Section 6.3). Further analysis through CAMx modeling that is underway is anticipated to show that BH does not have a perceptible visibility impact on these Class I areas. Therefore, the costs for the additional SO₂ emission control measure options are not reasonable.

²⁵ 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

Sections 4.2.4 through 4.2.7 provide a summary of the remaining factors evaluated for the SO₂ emission control measures, understanding that these projects represent substantial costs that are not justified on a cost per ton or absolute cost basis.

4.2.4 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 IDEM to modify BH's Title V operating permit to allow construction to commence, then to implement the project necessary to meet the SIP limit for the emission control measure, including capital funding, construction, tie-in to the process, commissioning, and performance testing.

The technologies would require significant resources and time of at least three to four years to engineer, permit, and install the equipment. However, prior to beginning this process, the SIP must first be submitted by IDEM in July 2021 and then approved by EPA, which is anticipated to occur within 12 to 18 months after submittal (approximately 2022 to 2023). Thus, the installation date would occur between 2024 and 2026. The 5-year average visibility impairment on the most impaired days at the associated Class I areas of interest is already below, or trending towards and expected to attain without additional emission reductions, the 2028 URP. Thus, weighing in the time necessary for compliance to the cost against the status and timeline for achieving reasonable progress goals further supports the conclusion that the substantial costs that are not justified.

4.2.5 Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance

The spray dryer absorbers and dry sorbent injection would increase energy usage due to the higher pressure drop across the absorber vessels (spray dryer absorber only) and new downstream baghouses, material preparation such as grinding reagents, additional material handling equipment such as pumps and blowers, and steam requirements. The cost of energy required to operate the spray dryer absorbers and dry sorbent injection have been included in the cost analyses found in Appendix C.4 through C.9.

The spray dryer absorbers and dry sorbent injection would generate additional solid waste that would require disposal in permitted landfills.

4.2.6 Factor 4 – Remaining Useful Life of the Source

Because BH is assumed to continue operations for the foreseeable future, the useful life of the individual emission control measures (assumed 20-year life, per Section 2.1.1.5) is used to calculate emission reductions, amortized costs and cost-effectiveness on a dollar per ton basis.

4.2.7 Visibility Benefits

Independent of the four-factor analysis, the installation of spray dryer absorbers and/or dry sorbent injection for the Power Station Boiler Nos. 7-12 are not appropriate and are unnecessary because:

1. The 5-year average visibility impairment on the most impaired days at the associated Class I areas of interest is already below (Mammoth Cave (492 km), Seney (511 km) and Isle Royale (708 km)), or trending towards and expected to attain without additional emission reductions (Mingo (568 km)), the 2028 URP (see Section 6.1),
2. The visibility impacts analysis completed to date indicates that BH is not a contributor to perceptible visibility impairment to the Class I areas on the most impaired days (see Section 6.3) and is not expected to have a perceptible contribution to visibility impacts based on CAMx modeling that is underway, and
3. Installation of spray dryer absorbers and dry sorbent injection for the Power Station Boiler Nos. 7-12 do not justify the associated costs, as described in Section 4.2.3, because the emission control measures are neither necessary to, nor expected to, provide perceptible visibility benefits (see Section 6.3).

4.2.8 Proposed SO₂ Emission Control Measures

Based on the four-factor analysis with visibility benefits evaluation, installation of additional SO₂ emission control measures at the Power Station Boiler Nos. 7-12 beyond those described in Section 2.2.2 are not required to make reasonable progress in reducing SO₂ emissions. As such, this analysis proposes to maintain the existing SO₂ emission control measures.

5 Blast Furnaces C and D

The following sections describe the four-factor analyses with visibility benefits evaluations for NO_x and SO₂ emission control measures for Blast Furnaces C and D.

5.1 Four-Factor Analysis – NO_x

The following sections describe the analysis for determining the reasonable set of NO_x emission control measures (Section 5.1.1), the four-factor analysis with visibility benefits evaluation (Sections 5.1.3 through 5.1.7), and the proposed emission control measures (Section 5.1.8) for the Blast Furnaces C and D Stoves, Casthouses, and Flares.

5.1.1 NO_x Emission Control Measures

5.1.1.1 Blast Furnaces C and D Stoves

The RBLC search (summarized in Appendix A) and search of air permits for I&S mills and similar sources (Appendix B) for Blast Furnace Stoves NO_x emission control measures identified the use of low-NO_x fuel or LNB at some sources. As described in Section 2.2.3, Blast Furnaces C and D already utilize low-NO_x fuel combustion (blast furnace gas) as an existing NO_x emission control measure.

The AK Steel Dearborn B and C Furnaces have LNB installed as part of a 2014 Prevention of Significant Deterioration (PSD) Permit; however, it is not clear that LNB offer any additional emission reduction potential compared to the existing NO_x emission control measures (blast furnace gas – low-NO_x fuel). EPA stated the following in a document titled “Alternative Control Techniques Document -- NO_x Emissions From Iron and Steel Mills”²⁶:

“[...] the primary fuel is BFG, which is largely CO, has a low heating value, and contains inerts, factors that reduce flame temperature. Thus, the NO_x concentration in blast furnace stove flue gas tends to be low and the potential for NO_x reduction is considered to be small.”

Additionally, the Briefing Sheet accompanying the 2010 Nucor Permit to Construct (PSD-LA-740) stated that LNB was eliminated as technically infeasible for the following rationale:

“Low NO_x burners limit the formation of NO_x by staging the addition of air to create a longer, cooler flame. The combustion of BFG in the hot blast stoves requires the supplement of a small amount of natural gas in order to maintain flame stability and prevent flame-outs of the burners. The use of low NO_x burners would attempt to stage fuel gas at the limits of combustibility and would prevent

²⁶ EPA, “Alternative Control Techniques Document – NO_x Emissions from Iron and Steel Mills” (EPA-453/R-94-065), 1994, Page 5-22

the operation of the hot blast stoves. Thus, low NO_x burners are not a feasible control technology for the hot blast stoves.”²⁷

Since LNB represent a negligible or potentially small emission reduction potential (if any), compared to the current NO_x emission control measures, and have potential operational challenges, LNB are not considered as part of the reasonable set of NO_x emission control measures for Blast Furnaces C and D Stoves and are not evaluated further in this analysis.

Therefore, the Blast Furnaces C and D Stoves have no reasonable set of NO_x emission control measures beyond what is currently installed and operated for these emission units based on the 2010 Nucor BACT, emission control measures described in the RBLC (Appendix A) and air permits for similar sources (Appendix B).

5.1.1.2 Blast Furnaces C and D Casthouses

The RBLC search (summarized in Appendix A) and search of air permits for II&S mills and similar sources (Appendix B) for Blast Furnace Casthouses did not identify any NO_x emission control measures. The RBLC search (Appendix A) did not include results for NO_x emissions from blast furnace casthouses. The 2010 Nucor BACT analysis did not evaluate NO_x emission control measures because Nucor Steel Louisiana did not estimate NO_x emissions for the casthouse in the associated permit application. This implies that the casthouse NO_x emissions were considered negligible for that project.

There are no additional NO_x emission control measures based on the emission control measures described in the RBLC (Appendix A) and air permits for II&S mills (Appendix B). As such, the Blast Furnaces C and D Casthouses have no reasonable set of NO_x emission control measures beyond what is currently installed and operated for these emission units.

5.1.1.3 Blast Furnaces C and D Flares

The RBLC search (summarized in Appendix A) and search of air permits for II&S mills and similar sources (Appendix B) for Blast Furnace Flares did not identify any NO_x emission control measures. There are no additional NO_x emission control measures based on the emission control measures described in the RBLC (Appendix A) and air permits for II&S mills (Appendix B). As such, the Blast Furnaces C and D Flares have no reasonable set of NO_x emission control measures beyond what is currently installed and operated for these emission units.

²⁷ Louisiana Department of Environmental Quality, Nucor Steel Permit to Construct (PSD-LA-740) Briefing Sheet, 2010, Page 23.

5.1.2 Baseline Emission Rates

Since the four-factor analysis concluded the Blast Furnaces C and D Stoves, Casthouses, and Flares have no reasonable set of NO_x emission control measures beyond what is currently installed and operated for these emission units, it is not necessary to represent a projected 2028 emissions scenario.

5.1.3 Factor 1 – Cost of Compliance

Since the four-factor analysis concluded the Blast Furnaces C and D Stoves, Casthouses, and Flares have no reasonable set of NO_x emission control measures beyond what is currently installed and operated for these emission units, it is not appropriate to estimate the cost of compliance for additional NO_x emission control measures.

5.1.4 Factor 2 – Time Necessary for Compliance

Since the four-factor analysis concluded the Blast Furnaces C and D Stoves, Casthouses, and Flares have no reasonable set of NO_x emission control measures beyond what is currently installed and operated for these emission units, it is not appropriate to describe the time that is necessary to achieve compliance for additional NO_x emission control measures.

5.1.5 Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance

Since the four-factor analysis concluded the Blast Furnaces C and D Stoves, Casthouses, and Flares have no reasonable set of NO_x emission control measures beyond what is currently installed and operated for these emission units, it is not appropriate to describe the energy and non-air quality environmental impacts for additional NO_x emission control measures.

5.1.6 Factor 4 – Remaining Useful Life of the Source

Since the four-factor analysis concluded the Blast Furnaces C and D Stoves, Casthouses, and Flares have no reasonable set of NO_x emission control measures beyond what is currently installed and operated for these emission units, it is not appropriate to describe the remaining useful life of the source.

5.1.7 Visibility Benefits

Since the four-factor analysis concluded the Blast Furnaces C and D Stoves, Casthouses, and Flares have no reasonable set of NO_x emission control measures beyond what is currently installed and operated for these emission units, it is not appropriate to describe the potential visibility benefits for additional NO_x emission control measures.

5.1.8 Proposed NO_x Emission Control Measures

The four-factor analysis concluded that additional NO_x emission control measures at the Blast Furnaces C and D Stoves, Casthouses, and Flares beyond those described in Section 2.2.3 are not required to make reasonable progress in reducing NO_x emissions. As such, this analysis proposes to maintain the existing NO_x emission control measures.

5.2 Four-Factor Analysis – SO₂

The following sections describe the analysis for determining the reasonable set of SO₂ emission control measures (Section 5.2.1), the four-factor analysis with visibility benefits evaluation (Sections 5.2.3 through 5.2.7), and the proposed emission control measures (Section 5.2.8) for the Blast Furnaces C and Stoves, Casthouses, and Flares.

5.2.1 SO₂ Emission Control Measures

5.2.1.1 Blast Furnaces C and D Stoves

The RBLC search (summarized in Appendix A) and search of air permits for II&S mills and similar sources (Appendix B) for Blast Furnace Stoves SO₂ emission control measures identified the use of low-sulfur fuel at one source. As described in Section 2.2.3, the Blast Furnaces C and D Stoves already routinely fire low-sulfur fuels (blast furnace gas and natural gas) as an existing SO₂ emission control measure.

AK Steel Dearborn (RBLCID = MI-0413) underwent SO₂ BACT in 2014 and concluded that BACT did not require additional SO₂ emission control measures. The 2010 Nucor BACT determined that other than the low-sulfur fuels (blast furnace gas and natural gas), no additional add-on SO₂ emission control measures are technically feasible.

There are no additional SO₂ emission control measures based on the 2010 Nucor BACT, emission control measures described in the RBLC (Appendix A) and air permits for II&S mills (Appendix B). As such, the Blast Furnaces C and D Stoves have no reasonable set of SO₂ emission control measures beyond what is currently installed and operated for these emission units.

5.2.1.2 Blast Furnaces C and D Casthouses

The RBLC search (summarized in Appendix A) and search of air permits for II&S mills and similar sources (Appendix B) for Blast Furnace Casthouses did not identify any SO₂ emission control measures. AK Steel Dearborn (RBLCID = MI-0413) underwent SO₂ BACT in 2014 and concluded that BACT did not require additional SO₂ emission control measures. The 2010 Nucor BACT stated that there are no feasible SO₂ emission control measures because of the corresponding low SO₂ concentration (~4 ppm SO₂) and high exhaust flow rate.

There are no additional SO₂ emission control measures based on the 2010 Nucor BACT, emission control measures described in the RBLC (Appendix A) and air permits for II&S mills (Appendix B). As such, the Blast Furnaces C and D Casthouses have no reasonable set of SO₂ emission control measures beyond what is currently installed and operated for these emission units.

5.2.1.3 Blast Furnaces C and D Flares

The RBLC search (summarized in Appendix A) and search of air permits for II&S mills and similar sources (Appendix B) for Blast Furnace Flares did not identify any SO₂ emission control measures. There are no additional SO₂ emission control measures based on the 2010 Nucor BACT, emission control measures described in the RBLC (Appendix A) and air permits for II&S mills (Appendix B). As such, the Blast Furnaces

C and D Flares have no reasonable set of SO₂ emission control measures beyond what is currently installed and operated for these emission units.

5.2.2 Baseline Emission Rates

Since the four-factor analysis concluded the Blast Furnaces C and D Stoves, Casthouses, and Flares have no reasonable set of SO₂ emission control measures beyond what is currently installed and operated for these emission units, it is not necessary to represent a projected 2028 emissions scenario.

5.2.3 Factor 1 – Cost of Compliance

Since the four-factor analysis concluded the Blast Furnaces C and D Stoves, Casthouses, and Flares have no reasonable set of SO₂ emission control measures beyond what is currently installed and operated for these emission units, it is not appropriate to estimate the cost of compliance for additional SO₂ emission control measures.

5.2.4 Factor 2 – Time Necessary for Compliance

Since the four-factor analysis concluded the Blast Furnaces C and D Stoves, Casthouses, and Flares have no reasonable set of SO₂ emission control measures beyond what is currently installed and operated for these emission units, it is not appropriate to describe the time that is necessary to achieve compliance for additional SO₂ emission control measures.

5.2.5 Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance

Since the four-factor analysis concluded the Blast Furnaces C and D Stoves, Casthouses, and Flares have no reasonable set of SO₂ emission control measures beyond what is currently installed and operated for these emission units, it is not appropriate to describe the energy and non-air quality environmental impacts for additional SO₂ emission control measures.

5.2.6 Factor 4 – Remaining Useful Life of the Source

Since the four-factor analysis concluded the Blast Furnaces C and D Stoves, Casthouses, and Flares have no reasonable set of SO₂ emission control measures beyond what is currently installed and operated for these emission units, it is not appropriate to describe the remaining useful life of the source.

5.2.7 Visibility Benefits

Since the four-factor analysis concluded the Blast Furnaces C and D Stoves, Casthouses, and Flares have no reasonable set of SO₂ emission control measures beyond what is currently installed and operated for these emission units, it is not appropriate to describe the potential visibility benefits for additional SO₂ emission control measures.

5.2.8 Proposed SO₂ Emission Control Measures

The four-factor analysis concluded that additional SO₂ emission control measures at the Blast Furnaces C and D Stoves, Casthouses, and Flares beyond those described in Section 2.2.3 are not required to make

reasonable progress in reducing SO₂ emissions. As such, this analysis proposes to maintain the existing SO₂ emission control measures.

6 Visibility Impacts Review

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.

Figure 6-1 shows a map of the BH facility relative to the four closest Class I areas. The Class I areas and the distance from the facility are:

- Mammoth Cave National Park – Kentucky (492 km)
- Seney National Wildlife Refuge – Michigan (511 km)
- Mingo National Wildlife Refuge – Missouri (568 km)
- Isle Royale National Park – Michigan (708 km)

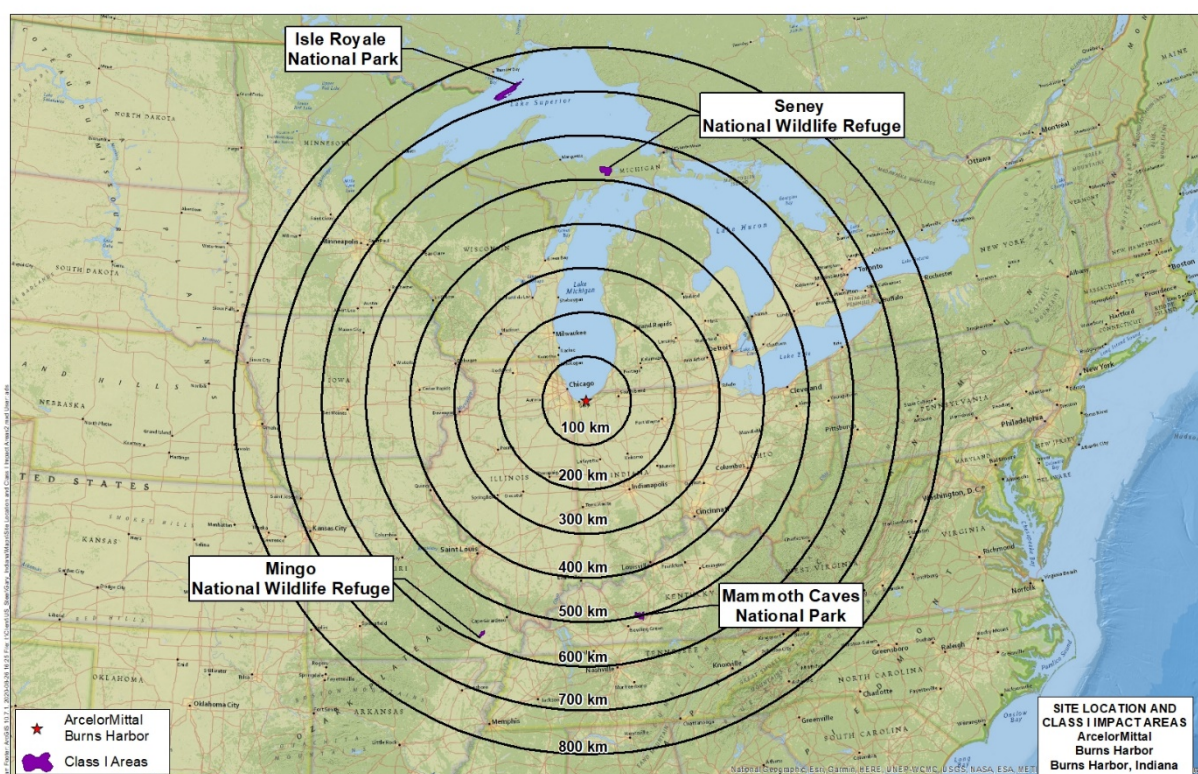


Figure 6-1 Location of Class I Areas in Relation to the Burns Harbor Facility

Section 6.1 provides an analysis of current visibility conditions at the four Class I areas presented in Figure 6-1 while Section 6.2 evaluates the emission trends that are impacting visibility in these Class I areas. Section 6.3 provides a review of previously completed visibility modeling and screening analysis which illustrate that emission reductions at BH are unlikely to improve visibility on the most impaired days at these Class I areas.

6.1 Visibility Conditions in the Closest Class I Areas

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”²⁸ for the relevant Class I areas. This information is used to establish the reasonable progress goals to be achieved by the end of the implementation period in 2028.²⁹ Barr conducted an analysis of the current visibility conditions at relevant Class I areas to determine the progress to date and status versus the 2028 URP glidepath. The relevant Class I areas are shown in Figure 6-1.

Visibility improvement is measured using data from the IMPROVE monitoring sites. The visibility metric is based on the 20% most anthropogenically impaired days and the 20% clearest days, with visibility being measured in deciviews (dV).

Figure 6-2 through Figure 6-5 show the rolling 5-year average visibility impairment based on IMPROVE monitoring data compared with the URP glidepath at Mammoth Cave (492 km), Mingo (568 km), Isle Royale (708 km), and Seney (511 km), respectively. As shown in these figures, the five-year average visibility metric has been improving for more than one decade at all four Class I areas. Impacts on the most impaired days at Mammoth Cave (492 km) (Figure 6-2), Isle Royale (708 km) (Figure 6-4), and Seney (511 km) (Figure 6-5) are already below the 2028 glidepath and have continued trending downward since. The visibility at Mingo (568 km) (Figure 6-3) is slightly above the 2028 glidepath but has been on a downward trend since 2007 and is expected to attain this threshold without additional emission reductions.

²⁸ 40 CFR 51.308(f)(1)

²⁹ 40 CFR 51.308(f)(3)

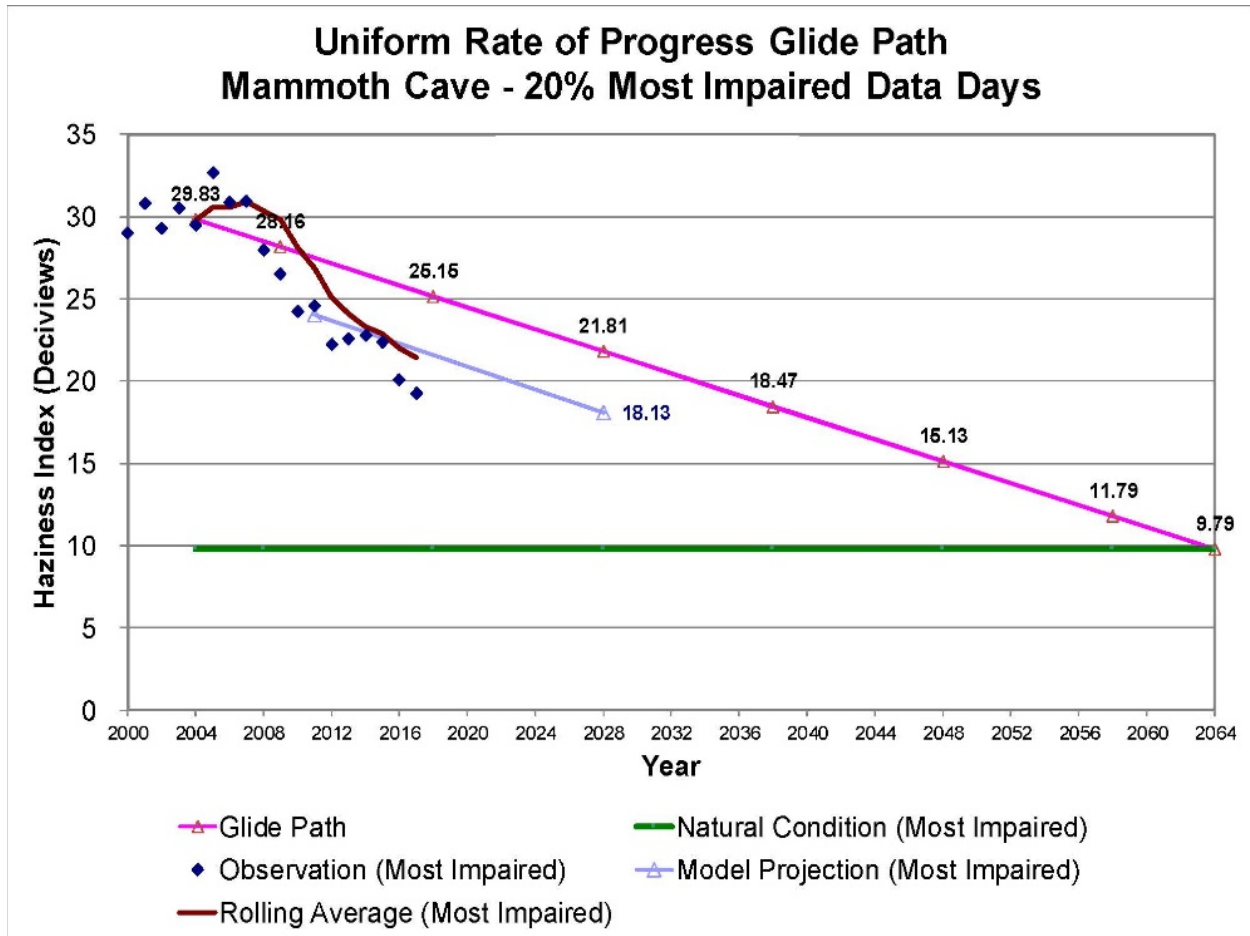


Figure 6-2 Visibility Trend versus URP – Mammoth Cave National Park (492 km)³⁰

³⁰ Jim Boylan – Georgia Department of Natural Resources, "VISTAS Regional Haze Project Update," 5/20/2020, Page 25. (<https://www.metro4-sesarm.org/sites/default/files/VISTAS%20Pres%20Stakeholders%20Final%20200520.pdf>)

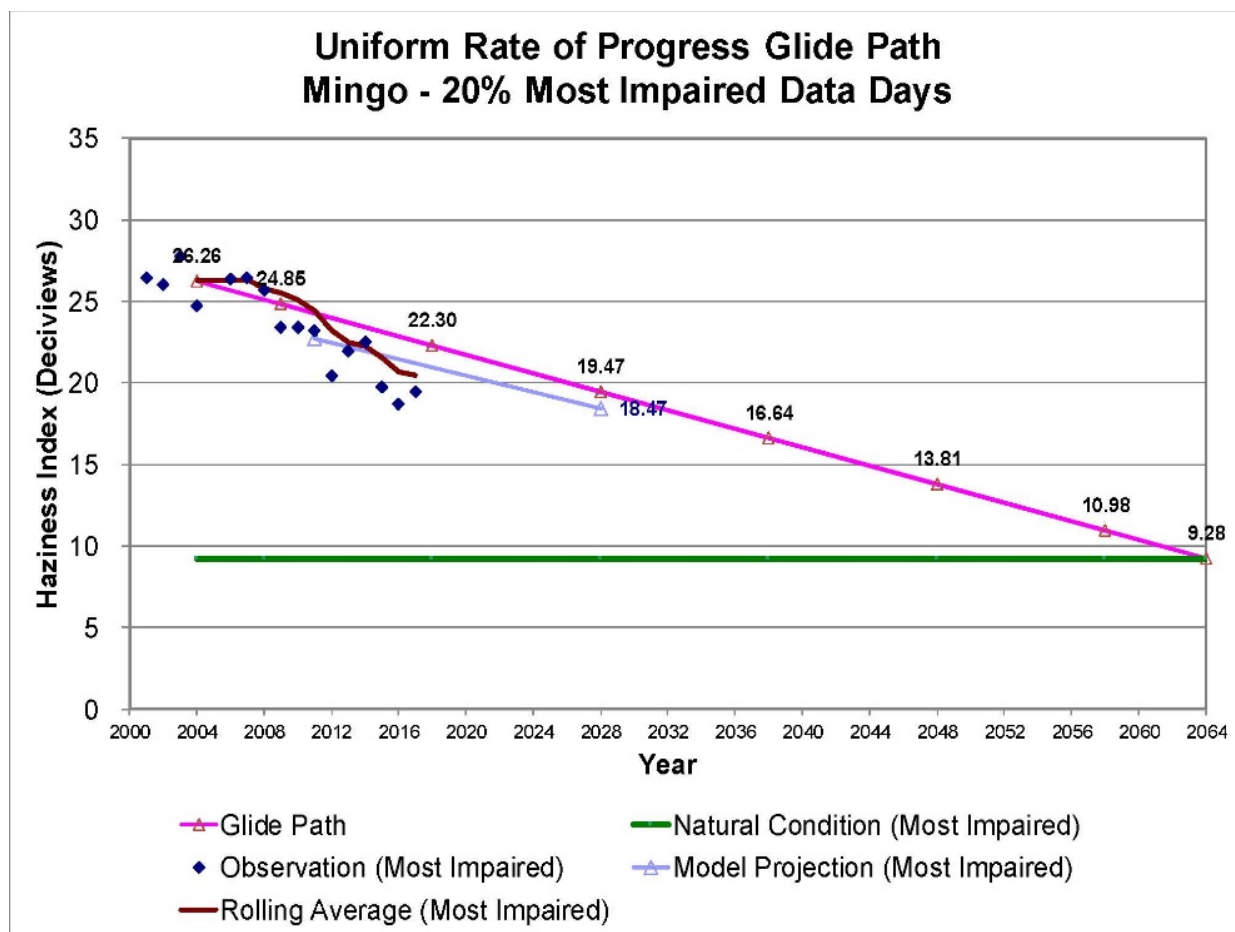


Figure 6-3 Visibility Trend versus URP – Mingo National Wildlife Refuge (568 km)³¹

³¹ Jim Boylan - Georgia Department of Natural Resources, "VISTAS Regional Haze Project Update," 5/20/2020, Page 37. (<https://www.metro4-sesarm.org/sites/default/files/VISTAS%20Pres%20Stakeholders%20Final%20200520.pdf>)

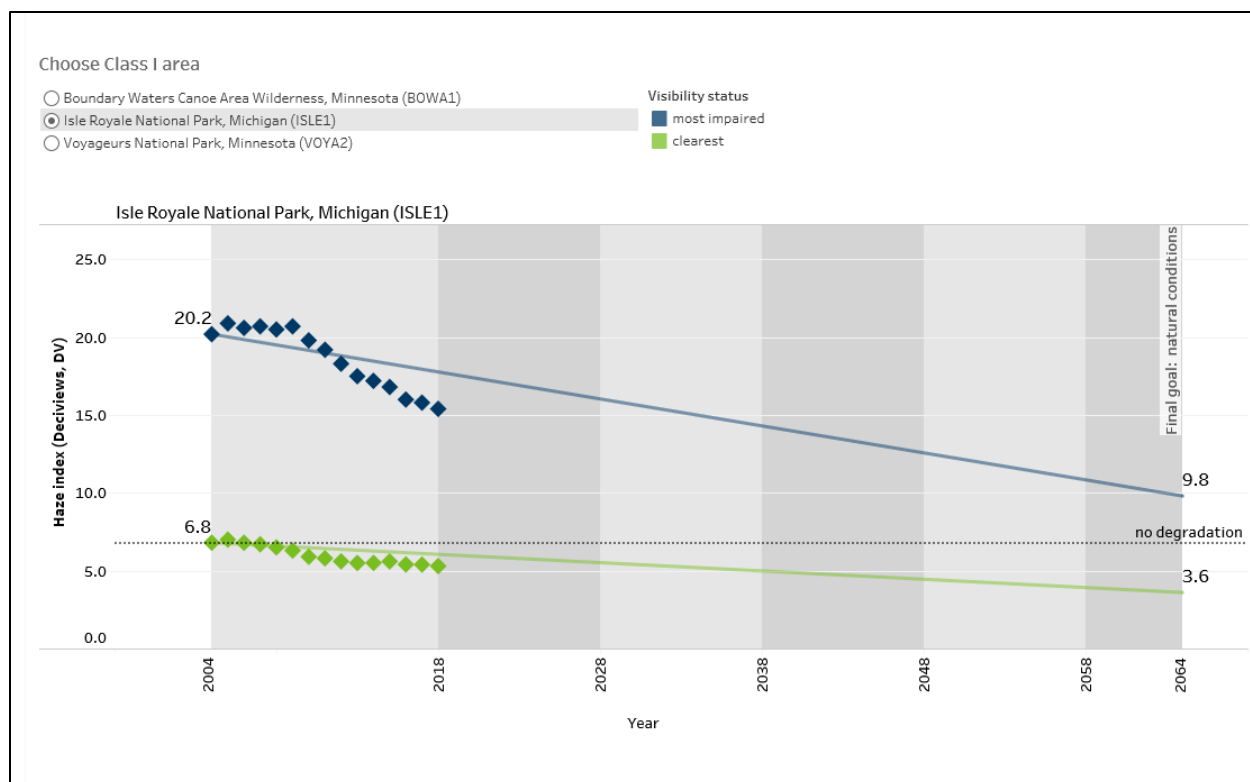


Figure 6-4 Visibility Trend versus URP – Isle Royale National Park (708 km)³²

³² Visibility trend from the Minnesota Pollution Control Agency website

(https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress)

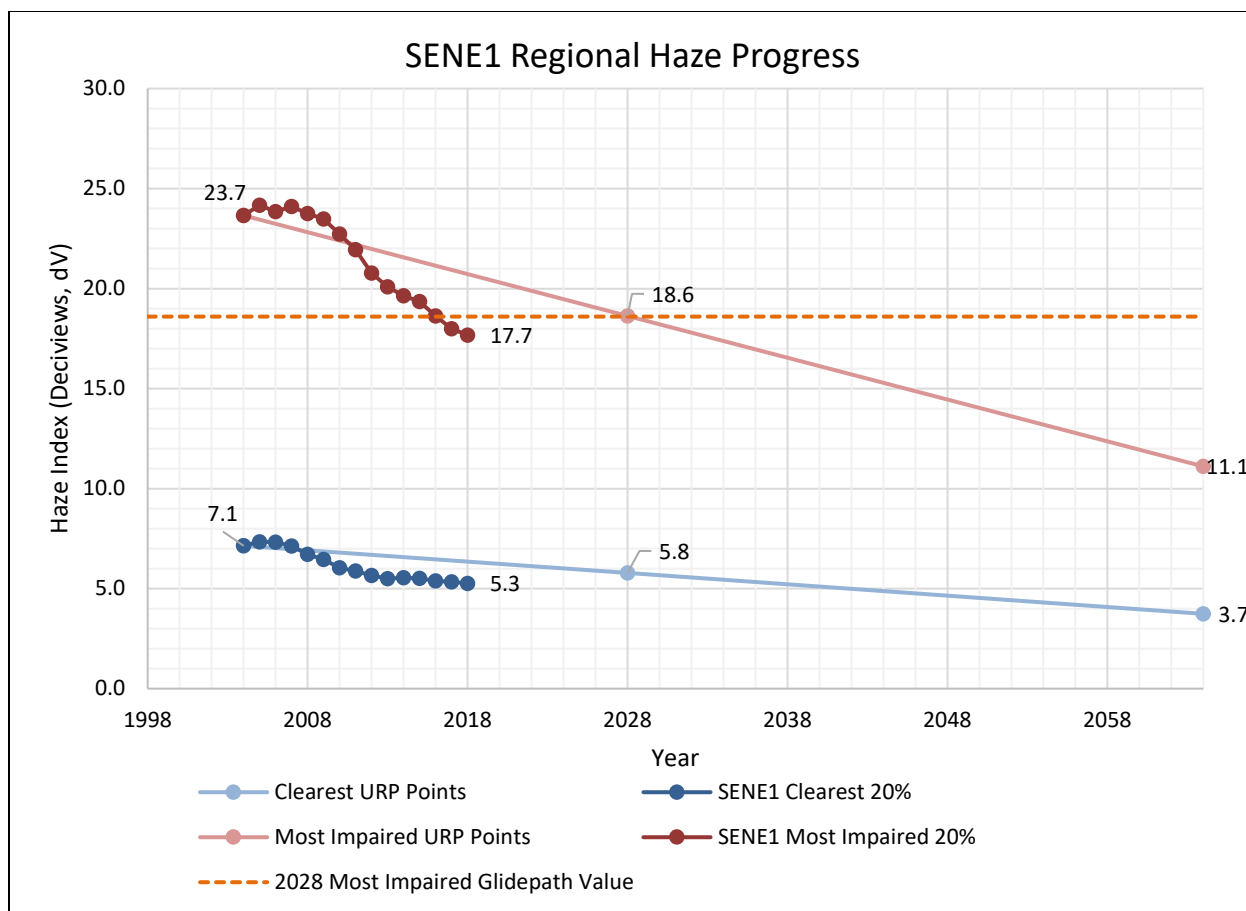


Figure 6-5 Visibility Trend versus URP – Seney National Wildlife Refuge (511 km) ³³

6.2 Emission Trend Analyses

The downward visibility trend for each of the Class I monitors illustrated above can be attributed to a number of different actions taken to reduce emissions NO_x and SO_2 from several sources, including:

- Installation of BART during the first RHR implementation period
- Emission reductions from a variety of industries, including the integrated iron and steel industry, due to equipment shutdowns and updated rules/regulations
- Transition of power generation systems from coal to natural gas and renewables, such as wind and solar

The trends for NO_x and SO_2 emissions are illustrated on a national and regional basis in Figure 6-6 and Figure 6-7, respectively.

³³ IMPROVE monitoring network (<http://vista.cira.colostate.edu/improve/>)

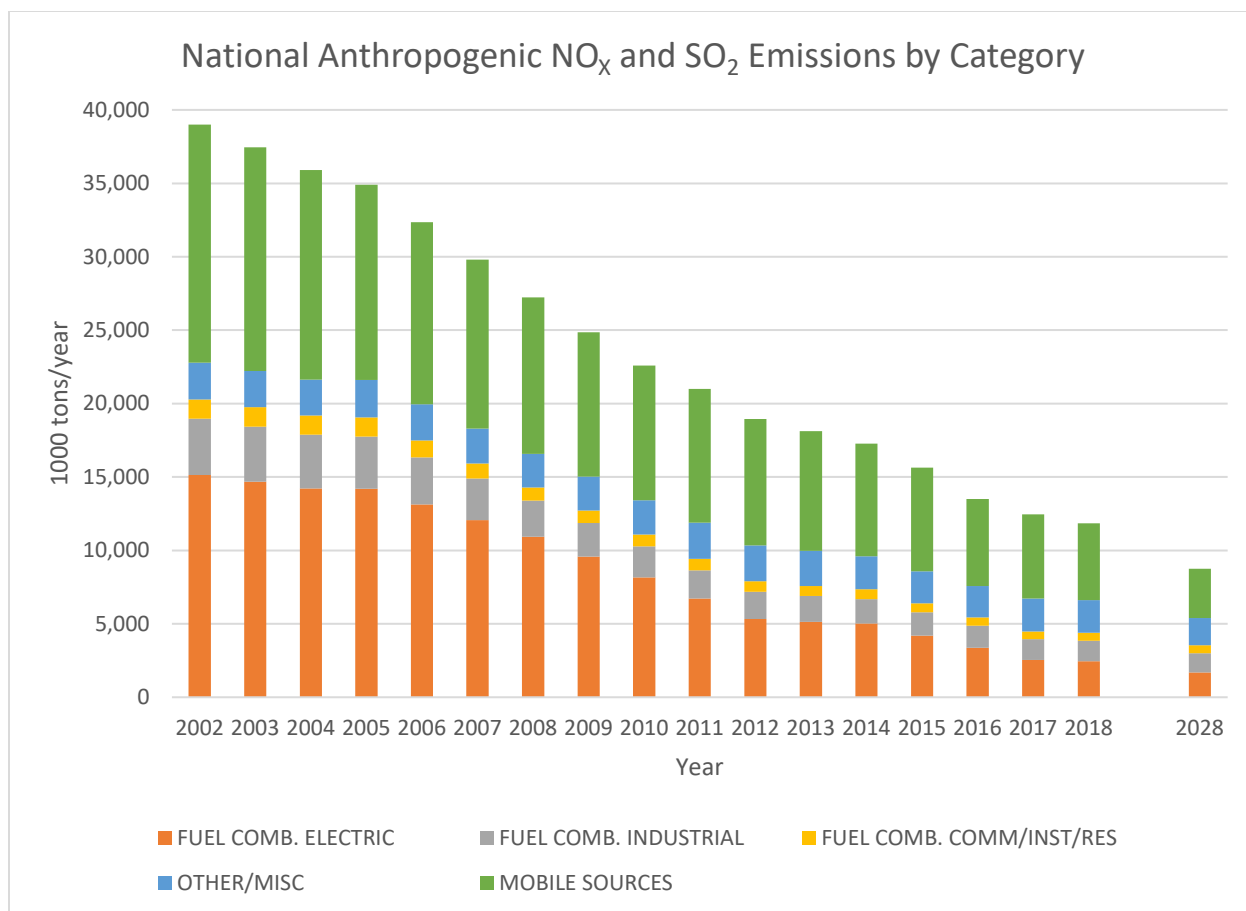


Figure 6-6 National NO_x and SO₂ Emission Trends

The national trends show a consistent pattern of emission reductions that will continue throughout the 2nd round of regional haze planning. There is a 35% reduction from 2016 to 2028 in national NO_x and SO₂ emissions. The emissions from 2002 – 2018 were developed based on information contained in the EPA's Air Pollutant Emission Trends Data³⁴ and the 2028 data was obtained from page 18 of EPA's regional haze modeling summary which includes the summary of modeled emissions³⁵.

³⁴ [EPA Air Pollutant Emission Trends Data, National Annual Emission Trend](#)

³⁵ https://www.epa.gov/sites/production/files/2019-10/documents/epa_rh_modeling_summary_101519-final_0.pdf

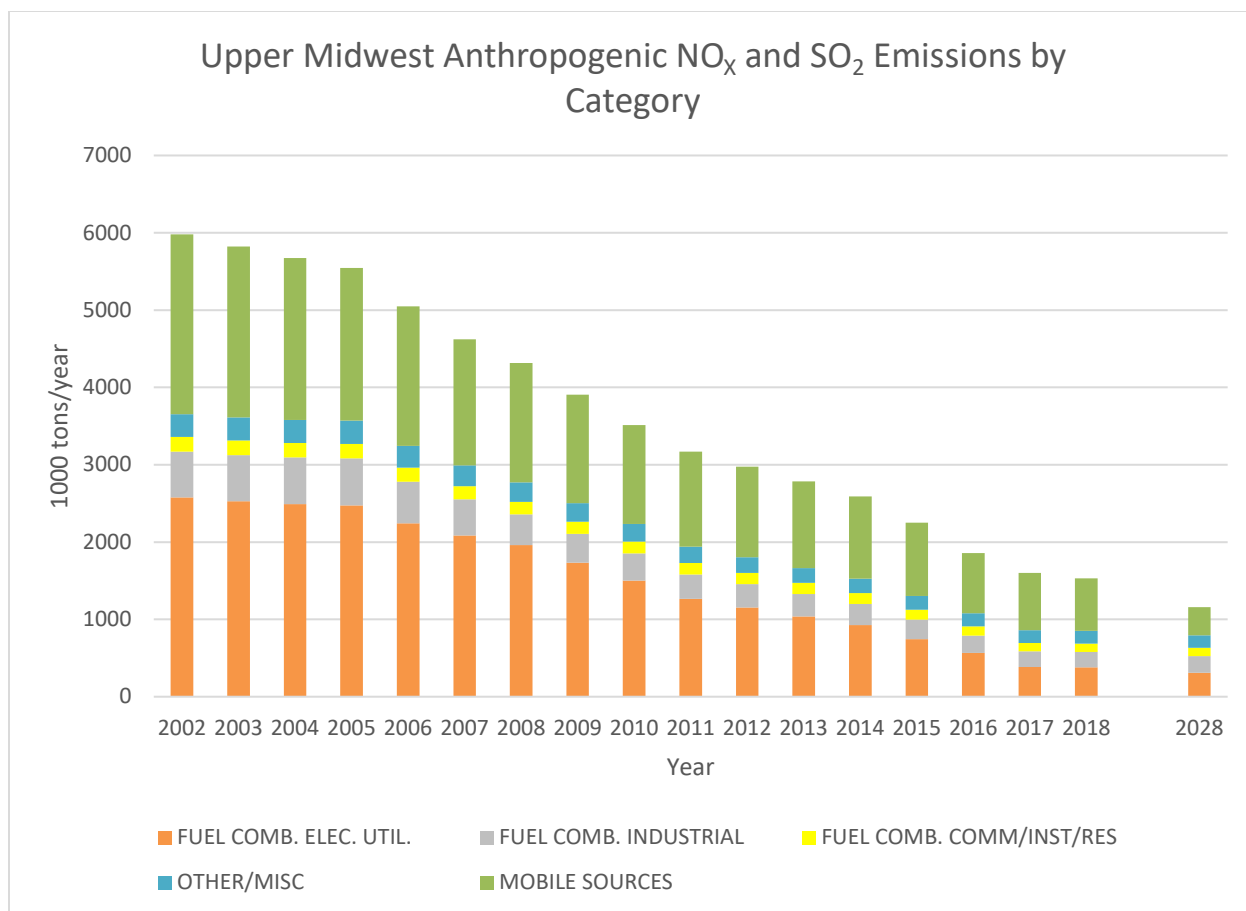


Figure 6-7 Upper Midwest NO_x and SO₂ Emission Trends

The regional summary also exhibits a significant reduction in NO_x and SO₂ emissions (35% from 2016 to 2028). The Upper Midwest region includes Illinois, Indiana, Michigan, Minnesota, and Wisconsin as areas that may impact the Class I areas near BH. The 2002-2018 emissions contained in the included state summaries was obtained from the EPA's state annual emission trends³⁶ and the 2028 data was obtained from the EPA's 2016v1 modeling platform that also includes 2028 modeling data³⁷.

In addition to these figures which provide confirmation of additional planned emission reductions, there are specific emission reductions that are planned prior to 2028 which will further improve the visibility in these Class I areas. Table 6-1 shows some of the upcoming emission reduction projects from states within the LADCO (IL, IN, MI, MN, and WI) except for Ohio since emission sources in Ohio are generally downwind of the affected Class I areas. In addition, many of the utility companies listed in Table 6-1 have

³⁶ [EPA Air Pollutant Emission Trends Data, State Annual Emission Trend](#)

³⁷ [EPA 2016v1 Modeling Inventory Platform FTP Reports](#)

carbon emission reduction goals beyond 2028, which will further reduce combustion and, therefore, NO_x and SO₂ emissions.

Table 6-1 Planned Emission Reduction Projects (IL, IN, MI, MN, WI) through 2028

Year	State	Company	Additional Emissions Reductions Expected/Projected
2020	IL	City Water, Light and Power	Dallman Units 31 & 32 Retirement ⁽¹⁾
2020	MI	Lansing Board of Water & Light	Eckert Plant Retirement ⁽²⁾
2021	MN	Otter Tail Power Company	Hoot Lake Plant Retirement ⁽³⁾
2021	WI	Dairyland Power Cooperative	Genoa Station No. 3 Retirement ⁽⁴⁾
2022	IL	Vistra Corp.	Edwards Plant Retirement ⁽⁵⁾
2022	MI	DTE Energy	Trenton Channel Power Plant Retirement ⁽⁶⁾
2022	MI	DTE Energy	St. Clair Power Plant Retirement ⁽⁶⁾
2022	WI	Alliant Energy	Edgewater Plant Retirement ⁽⁷⁾
2023	IL	City Water, Light and Power	Dallman Unit 33 Retirement ⁽¹⁾
2023	IN	Duke Energy	Gallagher Units 2 & 4 Retirement ⁽⁸⁾
2023	IN	Hoosier Energy	Merom Generating Station Retirement ⁽⁹⁾
2023	IN	Hoosier Energy	Transition to a more diverse generation mix including wind, solar, natural gas and storage ⁽⁹⁾
2023	IN	Indianapolis Power & Light	Petersburg Units 1 & 2 Retirement ⁽¹⁰⁾
2023	IN	NIPSCO	R.M. Schahfer Units 14, 15, 17, & 18 Retirement ⁽¹¹⁾
2023	IN	Vectren	Brown Units 1 & 2 and Culley Unit 2 Retirement ⁽¹²⁾
2023	IN	Vectren	Exit joint operations Warrick 4 coal unit ⁽¹²⁾
2023	MI	Consumers Energy	Karn Units 1 & 2 Retirement ⁽¹³⁾
2023	MI	DTE Energy	River Rouge Power Plant Retirement ⁽⁶⁾
2023	MN	Xcel Energy	Sherco Unit 2 Retirement ⁽¹⁴⁾
2025	MI	Lansing Board of Water & Light	Erickson Plant Retirement ⁽²⁾
2026	IN	Duke Energy	Gibson Unit 4 Retirement ⁽⁸⁾
2026	IN	Indiana Municipal Power Agency	Whitewater Valley Station Retirement ⁽¹⁵⁾
2026	MN	Xcel Energy	Sherco Unit 1 Retirement ⁽¹⁴⁾
2028	IN	Duke Energy	Cayuga Units 1-4 Retirement ⁽⁸⁾
2028	IN	Indiana Michigan Power	Rockport Unit 1 Retirement ⁽¹⁶⁾
2028	IN	NIPSCO	Michigan City Unit 12 Retirement ⁽¹¹⁾

Year	State	Company	Additional Emissions Reductions Expected/Projected
2028	MN	Xcel Energy	Allen S. King Plant Retirement ⁽¹⁴⁾

- (1) City Water Light and Power Integrated Resource Plan Update. Generation Unit Retirements. Public Forum Meeting. 1/29/2020.
- (2) Lansing Board of Water & Light 2020 Integrated Resource Plan
- (3) Otter Tail Power Company Application for Resource Plan Approval 2017-2031
- (4) <https://www.powermag.com/wisconsin-co-op-will-close-coal-fired-plant/>
- (5) <https://investor.vistracorp.com/investor-relations/news/press-release-details/2019/Environmental-Groups-Illinois-Power-Resources-Generating-LLC-Propose-Settlement-Agreement-to-Retire-Edwards-Coal-Plant-and-Fund-Community-Projects/default.aspx>
- (6) DTE 2019 Integrated Resource Plan Summary
- (7) <https://www.power-eng.com/2020/05/26/alliant-energy-closing-edgewater-coal-fired-plant-adding-six-solar-projects-in-wisconsin/>
- (8) Duke Energy Indiana Updated 2018 Integrated Resource Plan, 3/23/2020.
- (9) Hoosier Energy, "Hoosier Energy Announces New 20-Year Resource Plan," 01/21/2020.
<https://www.hoosierenergy.com/press-releases/hoosier-energy-announces-new-20-year-resource-plan/>
- (10) Indianapolis Power & Light Company 2019 Integrated Resource Plan
- (11) Northern Indiana Public Service Company LLC 2018 Integrated Resource Plan
- (12) Vectren 2019/2020 Integrated Resource Plan
- (13) Consumers Energy 2019 Clean Energy Plan
- (14) Xcel Energy Upper Midwest Integrated Resource Plan 2020-2034
- (15) Indiana Municipal Power Agency 2017 Integrated Resource Plan
- (16) Indiana Michigan Power Integrated Resource Planning Report, 7/1/2019.

The 2019 RH SIP Guidance says that the state will determine which emission control measures are necessary to make reasonable progress in the affected Class I areas.³⁸ However, as illustrated above, (1) the IMPROVE monitoring network data demonstrates sustained progress towards visibility goals, (2) the 5-year average visibility impairment on the most impaired days is already below the 2028 URP glidepath, and (3) additional emission reductions are already scheduled to occur.

Furthermore, additional emission reductions are already scheduled to occur. The IDEM should use the current trends of visibility improvement and the documented future emission reductions to demonstrate reasonable progress rather than imposing emissions reductions that are not cost effective in any event. The 5-year average visibility impairment on the most impaired days is already below the 2028 URP glidepath and additional emission reduction projects are scheduled to occur at other facilities with the potential to impact visibility in the affected Class I areas. Therefore, additional NO_x and SO₂ emission control measures at BH are not required to make reasonable progress in reducing NO_x and SO₂ emissions.

6.3 Visibility Impacts in the Closest Class I Areas

The 2019 RH SIP Guidance says that a state has "reasonable discretion to consider the anticipated visibility benefits of an emission control measure along with the other factors when determining whether a measure is necessary to make reasonable progress."³⁹ This guidance also says that "the decision-making

³⁸ US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," 08/20/2019, Page 9.

³⁹ US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," 08/20/2019, Page 37.

process by a state regarding a control measure may most often depend on how the state assesses the balance between the cost of compliance and the visibility benefits.”⁴⁰ Although the cost of compliance evaluations as presented in Sections 3.2.3 and 4.2.3 demonstrate that additional control measures are not cost effective, Barr completed an evaluation to determine if an emissions reduction at the facility would result in visibility improvements at the nearest Class I areas.

6.3.1 BART Modeling

As part of the previous regional haze planning evaluation, and to demonstrate that the BH source cannot reasonably be anticipated to cause or contribute to visibility impairment in a Class I area, ArcelorMittal completed site-specific visibility modeling of BH steel manufacturing operations in 2008 (see Appendix D). This effort included modeling the visibility impacts of baseline emissions (2002, 2003, and 2004 baseline periods) to determine whether the BART-eligible sources at the facility were subject to BART. According to the RHR, a facility was considered to “cause” visibility impairment if it is responsible for a 1.0 deciview change (delta-dV).⁴¹ Furthermore, a facility would be exempt from BART if its 98th percentile visibility impacts for baseline emissions are less than 0.5 delta-dV in each Class I area for each modeled year (i.e., determined to not contribute to visibility impairment).

The 2008 site-specific visibility modeling for BH was conducted using CALPUFF which, at the time, was the only EPA-approved model for predicting impacts for long-range emission transport beyond 50 km. The modeling analyzed the facility’s impact on visibility impairment at the four closest Class I areas: Mammoth Cave (492 km), Seney (511 km), Mingo (568 km), and Isle Royale (708 km). All Class I areas in the analysis are further than 300 km. The distance from the Class I areas is relevant to the analysis because CALPUFF is known to over predict impacts beyond 300 km.⁴² Thus, the results from this analysis are likely an over prediction, suggesting that the impact would be even less than reported.

EPA modeling guidance after the 2008 site-specific CALPUFF modeling suggests that photochemical modeling is the preferred method for identifying long-range transport source visibility impacts.⁴³ However, with the 2017 revisions to the *Guideline on Air Quality Models*⁴⁴, the EPA established the use of Lagrangian models such as CALPUFF as a very conservative screening method in order to streamline the time and resources necessary to conduct such long-range transport analyses. In addition, CALPUFF is still used as the first-level screening model by the Federal Land Managers’ Air Quality Related Values Work

⁴⁰ US EPA, “Guidance on Regional Haze State Implementation Plans for the Second Implementation Period,” 08/20/2019, Page 37.

⁴¹ Federal Register Vol. 70, No. 128, 07/06/2005, Page 39118. (<https://www.federalregister.gov/documents/2005/07/06/05-12526/regional-haze-regulations-and-guidelines-for-best-available-retrofit-technology-bart-determinations>)

⁴² Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts, Page 18. (<https://www3.epa.gov/scram001/7thconf/calpuff/phase2.pdf>)

⁴³ CALPUFF Regulatory Status, <http://www.src.com/calpuff/regstat.htm>

⁴⁴ Appendix W to 40 CFR Part 51

Group (FLAG).⁴⁵ Thus, the results of the 2008 site-specific visibility modeling using CALPUFF are still relevant and appropriate.

The 2008 site-specific CALPUFF modeling was conducted with extremely conservative assumptions for the maximum emission rates. The modeling was conducted using the highest calculated 24-hour SO₂ and NO_x emission rates for each of the 26 emission units individually (plus 3 volume sources). This provided a fictitious worst-case scenario because a complex facility such as BH cannot achieve the 24-hour maximum emission rates at all emission units simultaneously. Therefore, the modeled worst-case scenario conservatively overestimates the impacts on the Class I areas. However, even with these conservative assumptions, the modeled visibility impact was less than 0.5 delta-dV at all Class I areas and, therefore, the facility did not contribute a perceptible⁴⁶ amount to visibility impairment and was exempt from BART.

The current emissions of SO₂ and NO_x from BH are significantly less than the conservatively high emission rates which were used in the 2008 CALPUFF modeling. Therefore, the current visibility impacts would be even less than that concluded in the 2008 report.

CAMx modeling is also underway to further support this analysis. CAMx modeling for 2028 is planned to further support this analysis based on LADCO's 2016 base year emission inventory. The CAMx analysis is being conducted to calculate the individual facility impact on downwind Class I areas of interest. It includes full atmospheric chemistry and national emissions to best approximate the concentrations of pollutants in the Class I areas to allow for the calculation of specific impacts. BH reserves the right to amend and/or supplement this analysis once CAMx modeling has been completed, and which is similarly not expected to show a perceptible visibility impact from BH, even on the most impaired days.

6.3.2 Mammoth Cave and Mingo Trajectory Analysis

Consistent with the EPA Guidance on Regional Haze SIPs for the Second Implementation Plan, the VISTAS⁴⁷ and CENRAP⁴⁸ multi-state collaboratives developed tools that were used by their respective states to screen out sources from further analyses (i.e., the four-factor analysis). These analyses could be conducted using different approaches, including emissions / distance (Q/d), trajectory analyses to determine the likelihood of impact from sources on visibly impaired days, residence time analyses which was typically a more refined trajectory analyses, and/or photochemical grid modeling techniques.

In May 2020, Jim Boylan of the Georgia Department of Natural Resources provided a project update to VISTAS.⁴⁹ This update provides additional information related to the ArcelorMittal facilities and their lack of impact on Mammoth Cave (492 km). As described in the project update, VISTAS performed a

⁴⁵ 2010 FLAG Phase I Report Revised, <https://irma.nps.gov/DataStore/DownloadFile/420352>, October 2010, Page 23.

⁴⁶ Federal Register Vol. 70, No. 128, 07/06/2005, Page 39119. (<https://www.federalregister.gov/documents/2005/07/06/05-12526/regional-haze-regulations-and-guidelines-for-best-available-retrofit-technology-bart-determinations>)

⁴⁷ Visibility Improvement State and Tribal Association of the Southeast (VISTAS), <https://www.metro4-sesarm.org/>.

⁴⁸ Central Regional Air Planning Association (CENRAP), <https://www.cenrap.org/>.

⁴⁹ Jim Boylan - Georgia Department of Natural Resources, "VISTAS Regional Haze Project Update," 5/20/2020. (<https://www.metro4-sesarm.org/sites/default/files/VISTAS%20Pres%20Stakeholders%20Final%20200520.pdf>)

reasonable progress screening approach using a 2028-emission based Area of Influence (AOI) trajectory/residence time analysis and a Particulate Matter Source Apportionment Technology (PSAT) individual source evaluation for a number of Class I areas in the southeast and other Class I areas that could be impacted by VISTAS states' sources.

For the AOI trajectory analysis, the state of Kentucky used a threshold of 2% for sulfate or nitrate contribution to visibility impact at Mammoth Cave (492 km). Generally, the analysis evaluated 72-hour back trajectories on 20% most impaired days at each area and was used to identify facilities that were in the path of the trajectory to see how frequently their emissions potentially impacted the Class I area. Based on those analyses performed by VISTAS for Mammoth Cave (492 km), there were five sources in Indiana that were flagged for further analyses using photochemical modeling (i.e., flagged for the PSAT modeling analysis). BH was not identified in the AOI analysis as each of the flagged facilities were electric generating units. The VISTAS findings indicate that no additional analyses are necessary for BH as it was not included as specifically "flagged" sources in the PSAT modeling analysis.

Similarly, CENRAP also conducted AOI trajectory/residence time visibility impact analysis to screen out sources from further visibility analyses. The details of this analysis are described in documents obtained from the CENSARA website⁵⁰. The level of detail provided by CENRAP allows for a specific evaluation of the impacts from BH when compared to the state-selected threshold of 1% visibility culpability at Mingo in southeastern Missouri (568 km). The Missouri Department of Natural Resources used this 1% threshold (combined nitrate and sulfate) from the trajectory / residence time analysis to identify sources for further evaluation. Based on this analysis, BH did not exceed the 1% threshold as shown in Table 6-2.

Table 6-2 Sulfate and Nitrate Culpability at Mingo National Wildlife Refuge

Facility	Sulfate Culpability	Nitrate Culpability	Sulfate + Nitrate Culpability
Burns Harbor	0.19%	0.17%	0.18%

The CENRAP findings indicate that no additional analyses are necessary for BH as the facility was less than the 1% threshold for sulfate plus nitrate culpability. The findings also indicate that the BH facility was much lower than the 1% threshold for sulfate alone or for nitrate alone.

6.3.3 Seney and Isle Royale Back Trajectory Analysis

In addition to the screening approach completed using the CENRAP AOI trajectories, Barr completed a specific set of reverse particle trajectory analyses from Seney (511 km) and Isle Royale (708 km) to determine if emissions from BH could be contributing to visibility impacts in these Class I areas on the

⁵⁰ Central States Air Resources Agencies (CenSARA), "Determining Areas of Influence – CenSARA Round Two Regional Haze", November 2018, <https://censara.org/ftpfiles/Ramboll/>.

most impaired days. These analyses could also be used to determine if emission reductions at BH could result in visibility improvement on the most impaired days at these Class I areas.

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 within a specified time range. A reverse trajectory analysis was performed beginning at each Class I area for the most impaired days during 2017-2018. The impairment metric (dv) from the IMPROVE Aerosol RHR III dataset⁵¹ was used to calculate the 20% most impaired days for 2017 and 2018. The NOAA Hysplit model⁵² was used to calculate 48-hour reverse trajectories beginning at 6:00 PM at a height of 10m from each Class I area on the day from the calculated 20% most impaired days ("the most impaired trajectories"). This methodology was modeled after the Minnesota Pollution Control Agency's trajectory analysis for their Class I areas.⁵³

The analysis considered the 20% most impaired trajectories for each Class 1 area based on 2017 and 2018 IMPROVE data. The data set is generated by monitoring every third day. As shown in Figure 6–8 and Figure 6–9, only one of the most impaired trajectories crosses near BH for Seney (511 km) and none of the most impaired trajectories passes near BH for Isle Royale (708 km). In addition, these figures illustrate that the majority of the most impaired trajectories are not traveling from the general direction of BH or the greater Chicago area. Furthermore, most of the 48-hour reverse trajectories end before reaching BH and the greater Chicago area, indicating that Seney (511 km) and Isle Royale (708 km) are at a distance far enough away from the facility that a perceptible visibility impairment from the BH facility is extremely unlikely. These figures also demonstrate that sources from other regions, and not BH, are contributing to the visibility on the most impaired days at the monitors.

⁵¹ Malm, W. C., J. F. Sisler, D. Huffman, R. A. Eldred, and T. A. Cahill (1994), Spatial and seasonal trends in particle concentration and optical extinction in the United States, *J. Geophys. Res.*, 99, 1347-1370.
<http://views.cira.colostate.edu/fed/SiteBrowser/Default.aspx>

⁵² Stein, A.F., Draxler, R.R., Rolph, G.D., Stunder, B.J.B., Cohen, M.D., and Ngan, F., (2015). NOAA's HYSPLIT atmospheric transport and dispersion modeling system, *Bull. Amer. Meteor. Soc.*, 96, 2059-2077, <http://dx.doi.org/10.1175/BAMS-D-14-00110.1>

⁵³ MPCA – Regional Haze Tableau Public.
https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

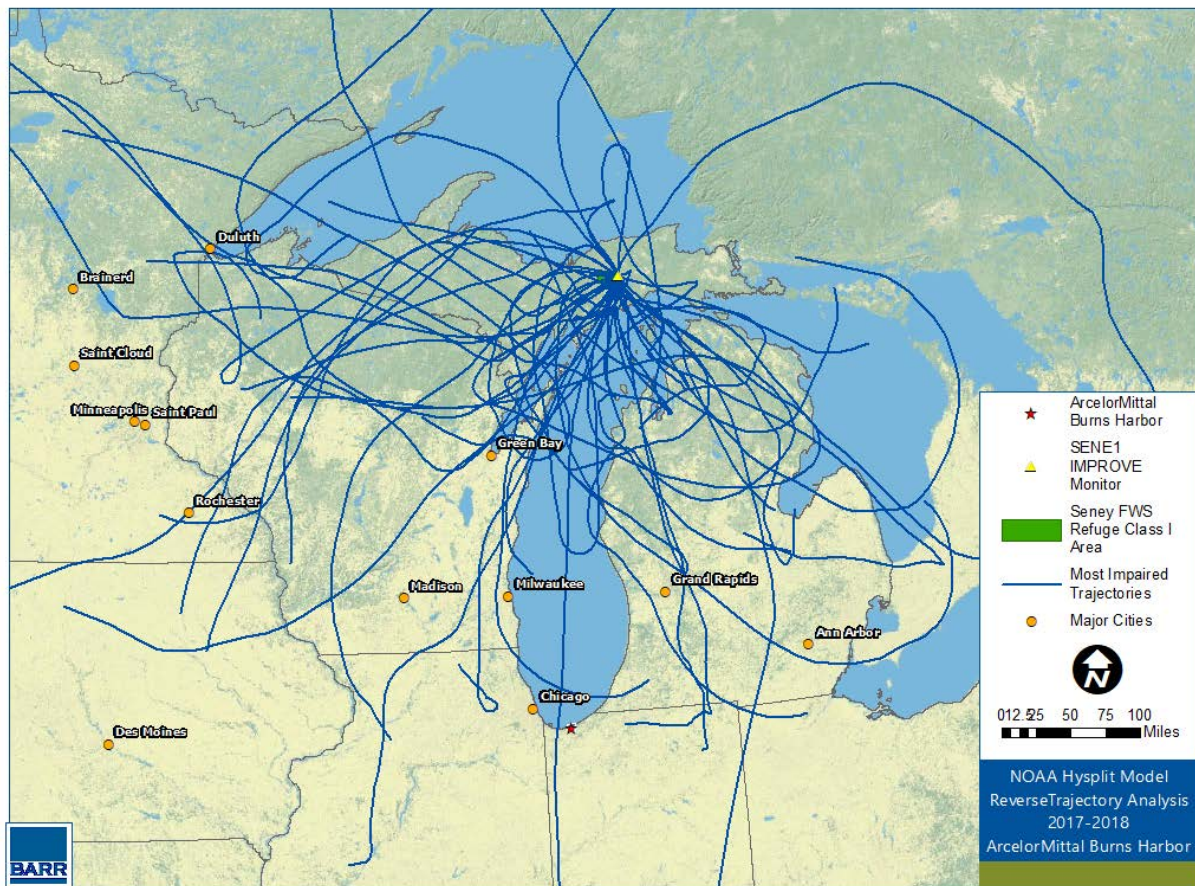
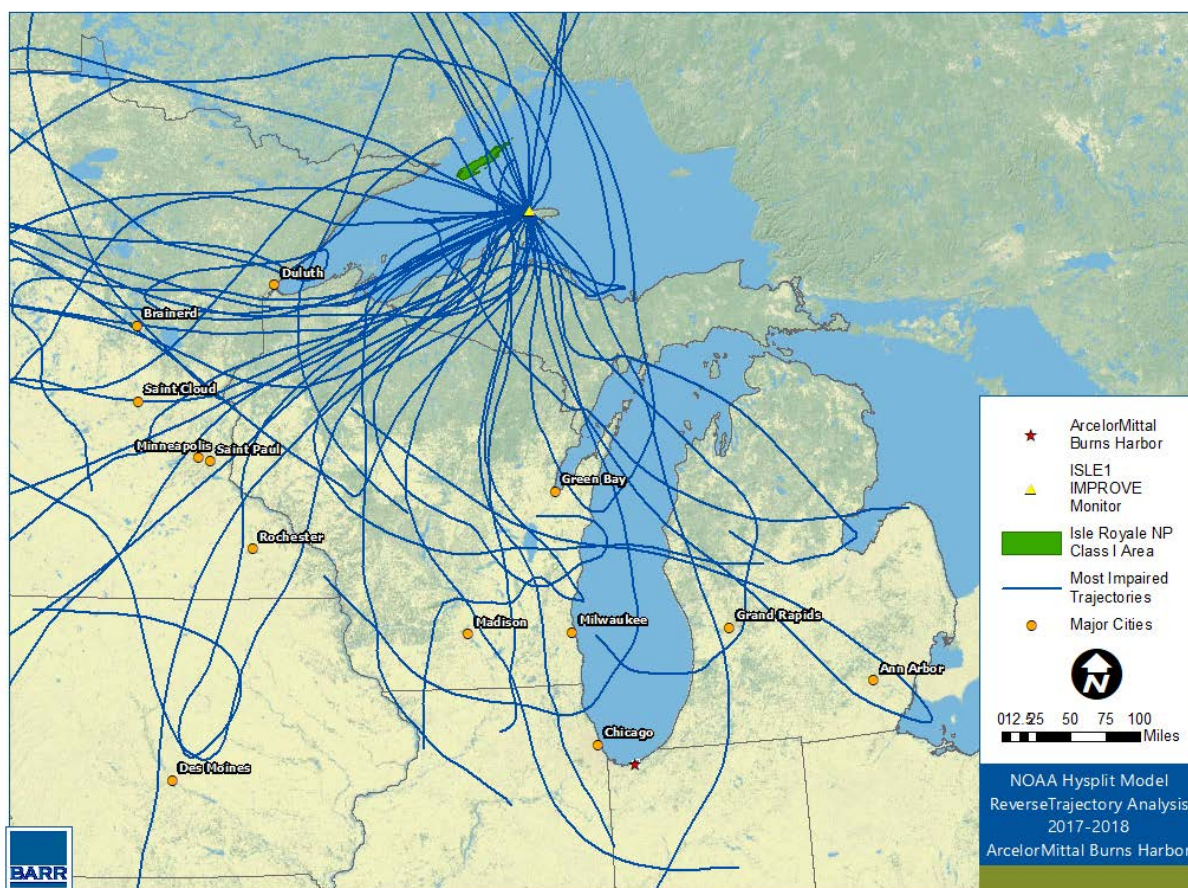


Figure 6–8 Seney National Wildlife Refuge: Most Impaired Trajectories for 2017-2018 from Reverse Trajectory Analysis



Note: ISLE1 IMPROVE Monitor is located at Eagle Harbor due to year-round accessibility purposes.

Figure 6–9 Isle Royale National Park: Most Impaired Trajectories for 2017-2018 from Reverse Trajectory Analysis

6.3.4 Visibility Impacts Conclusion

Based on the previous conservative BART modeling, the screening analyses conducted by VISTAS (Mammoth Cave (492 km)) and CENRAP (Mingo (568 km)), and the back trajectory analyses for Seney (511 km) and Isle Royale (708 km), Barr concludes that emissions from BH are not a contributor to perceptible visibility impairment on the most impaired days at the closest Class I areas. Thus, additional control measures implemented at the facility are unlikely to provide any improvement in perceptible visibility on the most impaired days and do not support imposing emissions reductions that are not cost effective in any event.

7 Conclusion

As described in Section 3, the Coke Oven Battery Nos. 1 and 2 four-factor analyses with visibility benefits evaluations concluded that:

- There is no reasonable set of NO_x emission control measures beyond what is currently installed and operated for the Coke Oven Battery Nos. 1 and 2 units. The reasonable set of additional NO_x emission control measures is not technically feasible for these emission units.
- The reasonable set of SO₂ emission control measures beyond what is currently installed and operated for these emission units consists of spray dryer absorbers⁴ or a coke oven gas desulfurization plant⁵.
- The associated SO₂ cost-effectiveness values (\$ per ton of emissions reduction) of the reasonable set of additional SO₂ emission control measures are not reasonable.
- Independent of the four-factor analysis, additional NO_x and SO₂ emission reductions are not appropriate and are unnecessary for these sources because:
 - The 5-year average visibility impairment on the most impaired days at the associated Class I areas of interest is already below (Mammoth Cave (492 km), Seney (511 km) and Isle Royale (708 km)), or trending towards and expected to attain without additional emission reductions (Mingo) (568 km), the 2028 URP (see Section 6.1), and
 - The visibility impacts analysis completed to date indicates that BH is not a contributor to perceptible visibility impairment to the Class I areas on the most impaired days, thus any installation of additional emission control measures at BH is not expected to have a perceptible impact on visibility in affected Class I areas and no further visibility improvements are necessary to meet the 2028 URP (see Section 6.3). Further analysis through CAMx modeling that is underway is anticipated to show that BH does not have a perceptible visibility impact on these Class I areas. BH reserves the right to amend and/or supplement this report and visibility analysis once CAMx modeling has been completed.
- Therefore, the Coke Oven Battery Nos. 1 and 2 existing NO_x and SO₂ emission performance are sufficient for the IDEM's regional haze reasonable progress goal.

Also as described in Section 3, the Clean Coke Oven Gas Export Line and Flare four-factor analyses with visibility benefits evaluations concluded that:

- There is no reasonable set of NO_x emission control measures for the Clean Coke Oven Gas Export Flare beyond what is currently installed and operated for this emission unit. There is no available set of additional NO_x emission control measures for this emission unit.

- It is not appropriate to evaluate NO_x emission control measures on the Clean Coke Oven Gas Export Line as it is simply a distribution line to other downstream sources, which have been independently evaluated as needed.
- The reasonable set of SO₂ emission control measures for the Clean Coke Oven Gas Export Line and Flare beyond what is currently installed and operated consists of coke oven gas desulfurization⁵.
- The associated SO₂ cost-effectiveness value (\$ per ton of emissions reduction) of the reasonable set of additional SO₂ emission control measures is not reasonable.
- As described in the Coke Oven Battery Nos. 1 and 2 conclusion above, additional NO_x and SO₂ emission reductions are not appropriate and are unnecessary for the Clean Coke Oven Gas Export Line and Flare, independent of the four-factor analysis, because BH is not expected to have a perceptible impact on visibility in affected Class I areas and no further visibility improvements are necessary to meet the 2028 URP (see Section 6).
- Therefore, the Clean Coke Oven Gas Export Line and Flare existing NO_x and SO₂ emission performance are sufficient for the IDEM's regional haze reasonable progress goal.

As described in Section 4, the Power Station Boiler Nos. 7-12 four-factor analyses with visibility benefits evaluations concluded that:

- There is no reasonable set of NO_x emission control measures beyond what is currently installed and operated for Power Station Boiler Nos. 7-12. The reasonable set of additional NO_x emission control measures is not technically feasible for these emission units.
- The reasonable set of SO₂ emission control beyond what is currently installed and operated for this emission unit consists of spray dryer absorbers, dry sorbent injection⁷ or a coke oven gas desulfurization plant.
- The associated SO₂ cost-effectiveness values (\$ per ton of emissions reduction) of the reasonable set of additional SO₂ emission control measures are not reasonable.
- As described in the Coke Oven Battery Nos. 1 and 2 conclusion above, additional NO_x and SO₂ emission reductions are not appropriate and are unnecessary for the Power Station Boiler Nos. 7-12, independent of the four-factor analysis, because BH is not expected to have a perceptible impact on visibility in affected Class I areas and no further visibility improvements are necessary to meet the 2028 URP (see Section 6).
- Therefore, the Power Station Boiler Nos. 7-12 existing NO_x and SO₂ emission performance are sufficient for the IDEM's regional haze reasonable progress goal.

As described in Section 5, the Blast Furnaces C and D four-factor analyses with visibility benefits evaluations concluded that:

- There is no reasonable set of NO_x and SO₂ emission control measures beyond what is currently installed and operated for these emission units. The reasonable set of additional NO_x emission control measures either represent no or negligible emission reduction potential and may otherwise be technically infeasible for these emission units.
- As described in the Coke Oven Battery Nos. 1 and 2 conclusion above, additional NO_x and SO₂ emission reductions are not appropriate and are unnecessary for Blast Furnaces C and D, independent of the four-factor analysis, because BH is not expected to have a perceptible impact on visibility in affected Class I areas and no further visibility improvements are necessary to meet the 2028 URP (see Section 6).
- Therefore, the Blast Furnaces C and D existing NO_x and SO₂ emission performance are sufficient for the IDEM's regional haze reasonable progress goal.