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 (SO_2) for the Clean Coke Oven Gas Export Line, Battery Nos. 1 and 2, Power Station Boiler Nos. 7-12, and Blast Furnaces C and D[2]. 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) guidance[3] 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 NOx emission control measures is not technically feasible for these emission units.

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[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 SO_2 emission control measures beyond what is currently installed and operated for these emission units consists of spray dryer absorbers[4] or a coke oven gas desulfurization plant[5].

- The associated SO_2 cost-effectiveness values ($ per ton of emissions reduction) of the reasonable set of additional SO_2 emission control measures are not reasonable.

- Independent of the four-factor analysis, additional NO_X and SO_2 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 perceptible[6] 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 SO_2 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:

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[4] Spray dryer absorber systems spray lime slurry into an absorption tower where SO_2 is absorbed by the slurry, forming $CaSO_3/CaSO_4$. The liquid-to-gas ratio is such that the water evaporates before the droplets reach the bottom of the tower. The dry solids are 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 SO_2 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 desulfurization[5].

- The associated SO_2 cost-effectiveness value ($ per ton of emissions reduction) of the reasonable set of additional SO_2 emission control measures is not reasonable.

- As described in the Coke Oven Battery Nos. 1 and 2 conclusion above, additional NO_X and SO_2 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 SO_2 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 NOx emission control measures is not technically feasible for these emission units.

- The reasonable set of SO_2 emission control beyond what is currently installed and operated for this emission unit consists of spray dryer absorbers, dry sorbent injection[7] or a coke oven gas desulfurization plant.

- The associated SO_2 cost-effectiveness values ($ per ton of emissions reduction) of the reasonable set of additional SO_2 emission control measures are not reasonable.

- As described in the Coke Oven Battery Nos. 1 and 2 conclusion above, additional NO_X and SO_2 emission reductions are not appropriate and are unnecessary for the Power Station Boiler Nos. 7-

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[7] Dry sorbent (pulverized lime or limestone) is directly injected into the duct upstream of a new fabric filter. SO_2 reacts with the sorbent, and the solid particles are collected with a fabric filter. Further SO_2 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 SO_2 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 SO_2 emission control measures beyond what is currently installed and operated for these emission units. The reasonable set of additional NOx 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 SO_2 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 SO_2 emission performance are sufficient for the IDEM's regional haze reasonable progress goal.

The NO_X and SO_2 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 SO_2 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	Battery No. 1 = $6,300 Battery No. 2 = $5,300	3-4 years after SIP promulgation	Energy -Increased energy use to accommodate differential pressure. -Increased indirect emissions at power plant to accommodate the increased energy use. Environmental -Additional solid waste generation and disposal.	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	Energy -Increased indirect emissions at power plant to accommodate the increased energy use. Environmental -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	No. 7 = $16,100 No. 8 = $21,700 No. 9 = $26,800 No. 10 = $42,000 No. 11 = $25,300 No. 12 = $20,300	3-4 years after SIP promulgation	Energy -Increased energy use to accommodate differential pressure. -Increased indirect emissions at power plant to accommodate the increased energy use. Environmental -Additional solid waste generation and disposal.	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	No. 7 = $8,800 No. 8 = $9,900 No. 9 = $11,500 No. 10 = $16,700 No. 11 = $10,900 No. 12 = $10,000	3-4 years after SIP promulgation	Energy -Increased energy use to accommodate differential pressure. -Increased indirect emissions at power plant to accommodate the increased energy use. Environmental -Additional solid waste generation and disposal.	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 SO_2 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 SO_2 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 SO_2 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

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[8] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003., Page 28.

[9] Ibid, Page 29.

[10] 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 Louisiana[12] (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

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[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 SO_2 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.

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[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 SO_2 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 gas[18]. 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.

NOx and SO_2 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 SO_2 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 SO_2 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 SO_2 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 SO_2 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 SO_2 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 SO_2 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 SO_2 emission control measures.

2.3 Facility-wide NO_X and SO_2 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 SO_2 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 SO_2 emissions from 2005 to 2019. BH has already reduced NO_X and SO_2 emissions by 18% from 2005 (2005 = 25,023 tons/year NO_X and SO_2, 2019 = 20,415 tons/year NO_X and SO_2) 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.

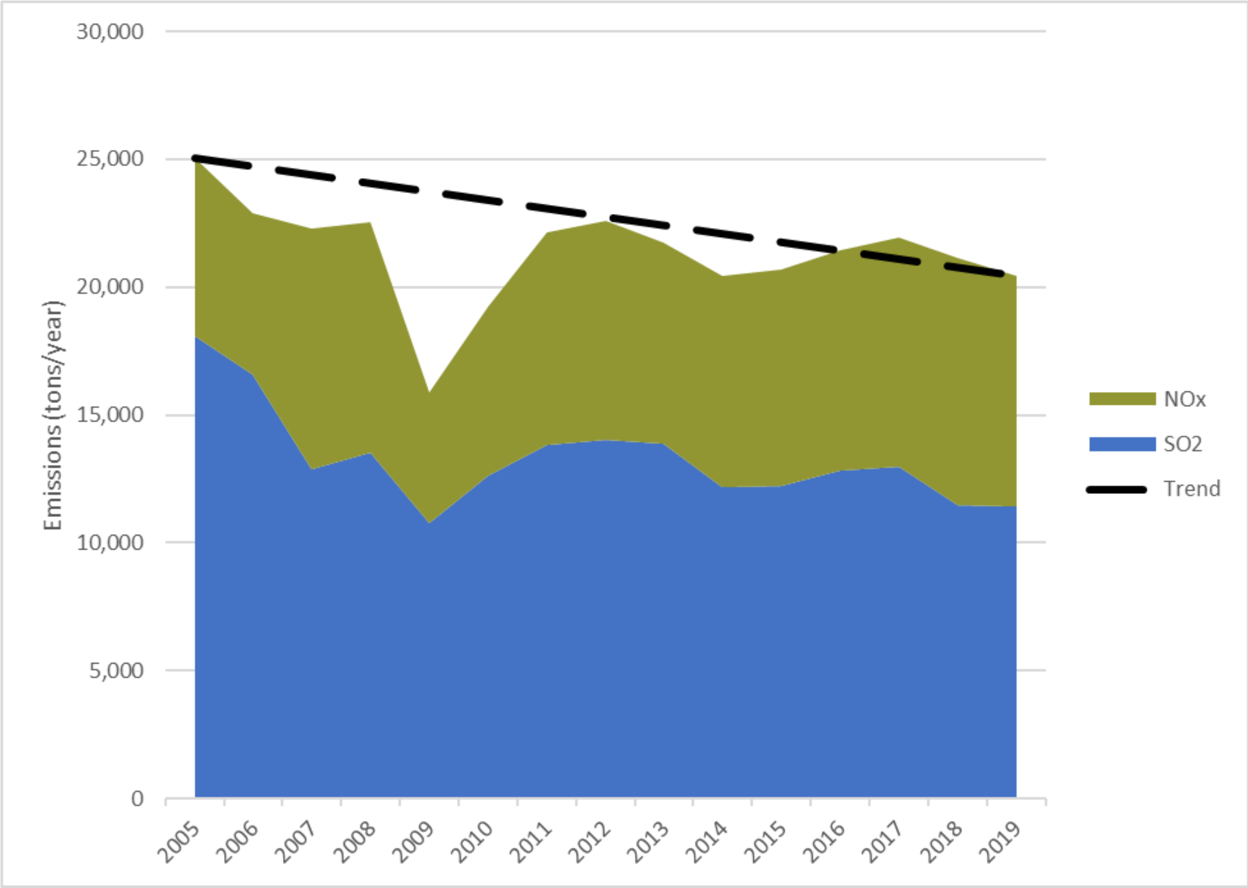

Figure 2-1 Facility-wide NO_X and SO_2 Emissions from 2005 to 2019

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 SO_2 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 Manual[19]:

[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 units[18] are dependent on the burner-specific characteristics (e.g., flame temperature, O_2 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 – SO_2

The following sections describe the analysis for determining the reasonable set of SO_2 emission control measures (Section 3.2.1), the 2028 projected baseline SO_2 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 SO_2 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 SO_2 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 SO_2 emission control measures.

Wet scrubbers[20] can offer SO_2 control performance levels that are generally consistent with spray dryer absorbers[4]. 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 SO_2 emission control measures for the Battery Nos. 1 and 2.

BH identified coke oven gas treatment through the installation of a desulfurization plant[5] to be part of the reasonable set of SO_2 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 SO_2 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 SO_2 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 SO_2 emission control measure.

BH identified installation of coke oven gas desulfurization to be part of the reasonable set of SO_2 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 Line[18] is evaluated as a SO_2 emission control measure in Sections 3.2.3 through 3.2.7.

[20] Wet scrubbing, when applied to remove SO_2, 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 SO_2 in the waste gas. Crushed limestone, lime, or caustic are used as scrubbing agents. Typical high-efficiency SO_2-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 II&S mills and similar sources (Appendix B) for Coke Oven Battery Flares SO_2 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 SO_2 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 SO_2 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 SO_2 emissions are shown in Table 3-1.

Table 3-1 Estimated 2028 Baseline SO_2 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 SO_2 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 Manual[21], 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.

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[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 SO_2 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 SO_2 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 SO_2 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 SO_2 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 SO_2 Emission Control Measures

Based on the four-factor analysis with visibility benefits evaluation, installation of additional SO_2 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 SO_2 emissions. As such, this analysis proposes to maintain the existing SO_2 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 SO_2 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 NOx 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 Manual[19]:

> "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 - SO_2

The following sections describe the analysis for determining the reasonable set of SO_2 emission control measures (Section 4.2.1), the 2028 projected baseline SO_2 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 SO_2 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 SO_2 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 SO_2 emission control measure.

It is not appropriate to compare SO_2 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 fuel[24] (e.g., natural gas, blast furnace gas).Wet scrubbers, spray dryer absorbers, and dry sorbent injection[7] are common add-on SO_2 emission control measures applied to boilers in other industries.

Wet scrubbers can offer SO_2 control performance levels that are generally consistent with spray dryer absorbers and dry sorbent injection. However, wet scrubbers produce substantial amounts of sulfate-

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[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 SO_2 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 SO_2 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 SO_2 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 SO_2 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 SO_2 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 Manual[25], 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 SO_2 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 SO_2 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 SO_2 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 SO_2 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 SO_2 Emission Control Measures

Based on the four-factor analysis with visibility benefits evaluation, installation of additional SO_2 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 SO_2 emissions. As such, this analysis proposes to maintain the existing SO_2 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 SO_2 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 II&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 NOx 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 – SO_2

The following sections describe the analysis for determining the reasonable set of SO_2 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 SO_2 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 SO_2 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 SO_2 emission control measure.

AK Steel Dearborn (RBLCID = MI-0413) underwent SO_2 BACT in 2014 and concluded that BACT did not require additional SO_2 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 SO_2 emission control measures are technically feasible.

There are no additional SO_2 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 SO_2 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 SO_2 emission control measures. AK Steel Dearborn (RBLCID = MI-0413) underwent SO_2 BACT in 2014 and concluded that BACT did not require additional SO_2 emission control measures. The 2010 Nucor BACT stated that there are no feasible SO_2 emission control measures because of the corresponding low SO_2 concentration (~4 ppm SO_2) and high exhaust flow rate.

There are no additional SO_2 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 SO_2 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 SO_2 emission control measures. There are no additional SO_2 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 SO_2 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 SO_2 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 SO_2 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 SO_2 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 SO_2 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 SO_2 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 SO_2 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 SO_2 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 SO_2 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 SO_2 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 SO_2 emission control measures.

5.2.8 Proposed SO_2 Emission Control Measures

The four-factor analysis concluded that additional SO_2 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 SO_2 emissions. As such, this analysis proposes to maintain the existing SO_2 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)

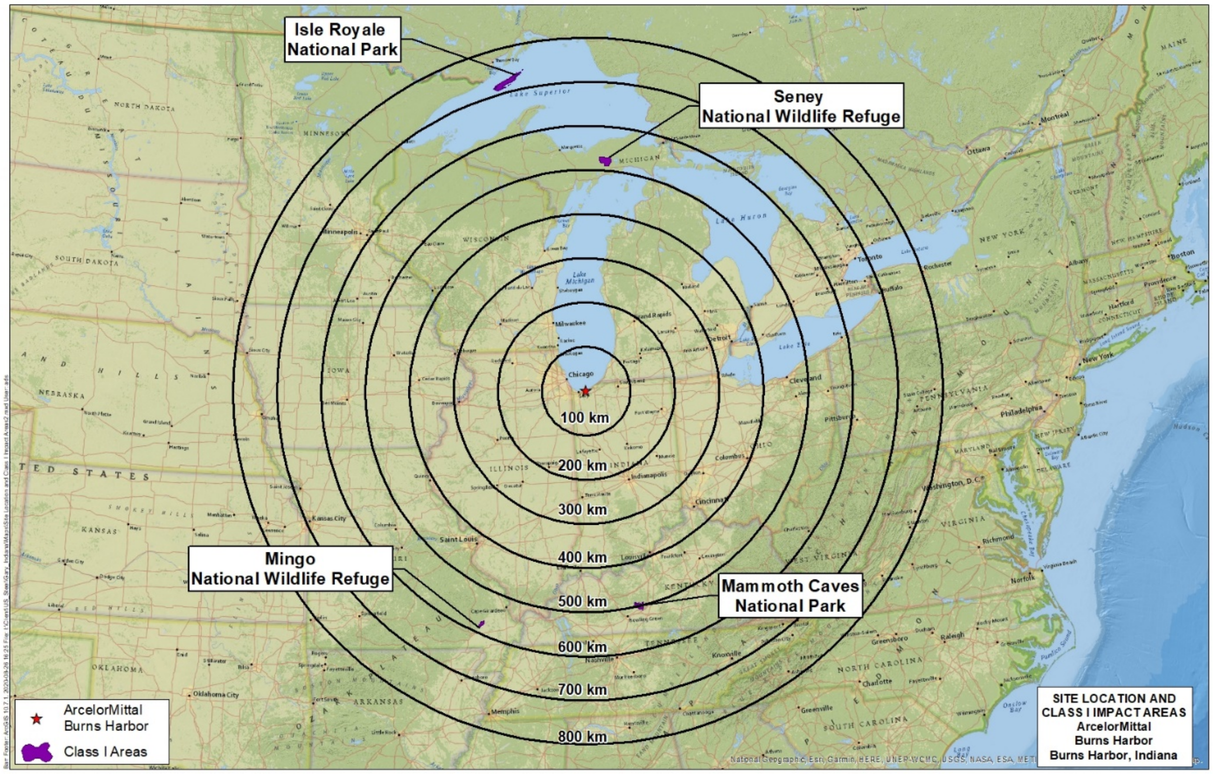

Figure 6-1 Location of Class I Areas in Relation to the Burns Harbor Facility

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)

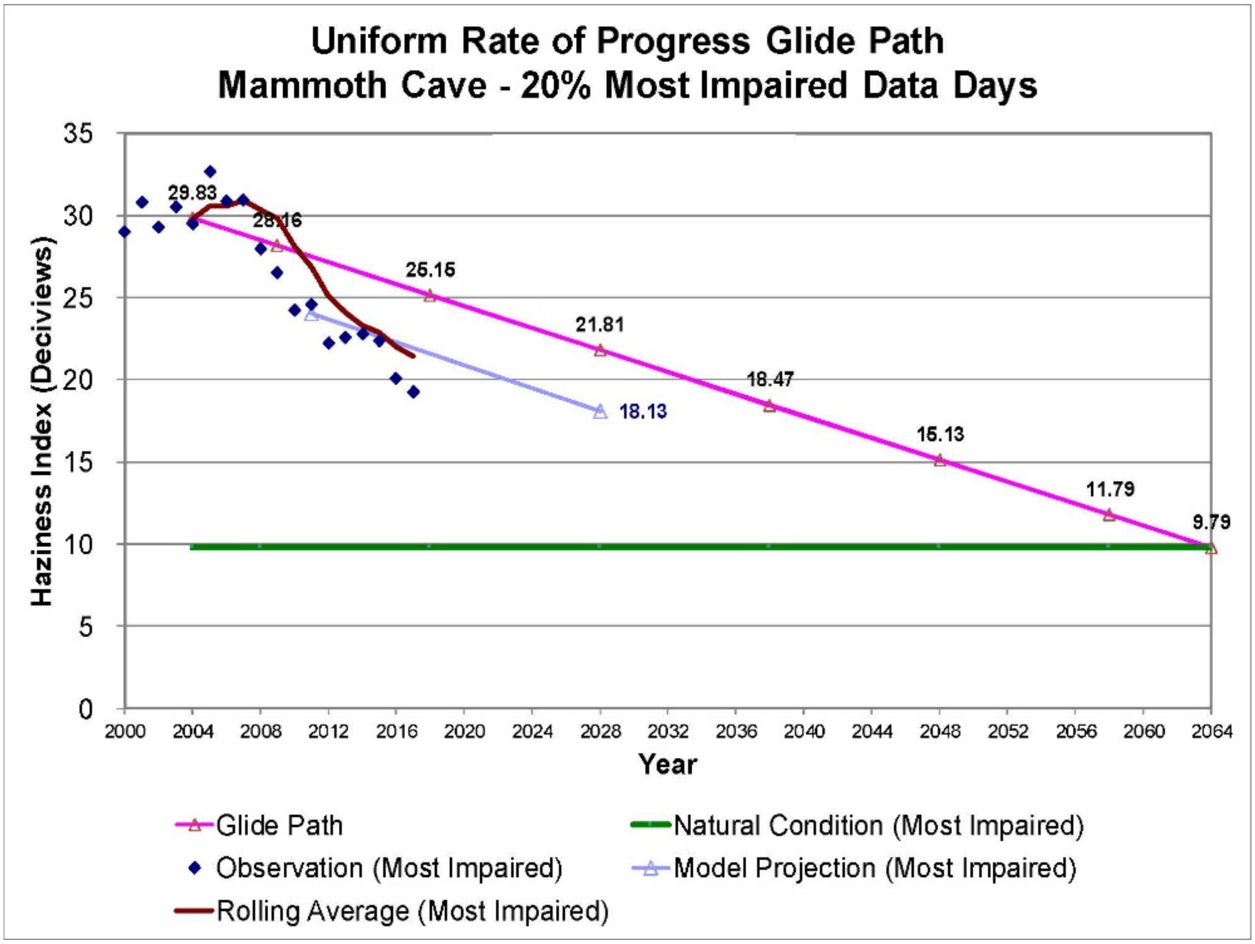

Figure 6-2 Visibility Trend versus URP – Mammoth Cave National Park (492 km)[30]

[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)

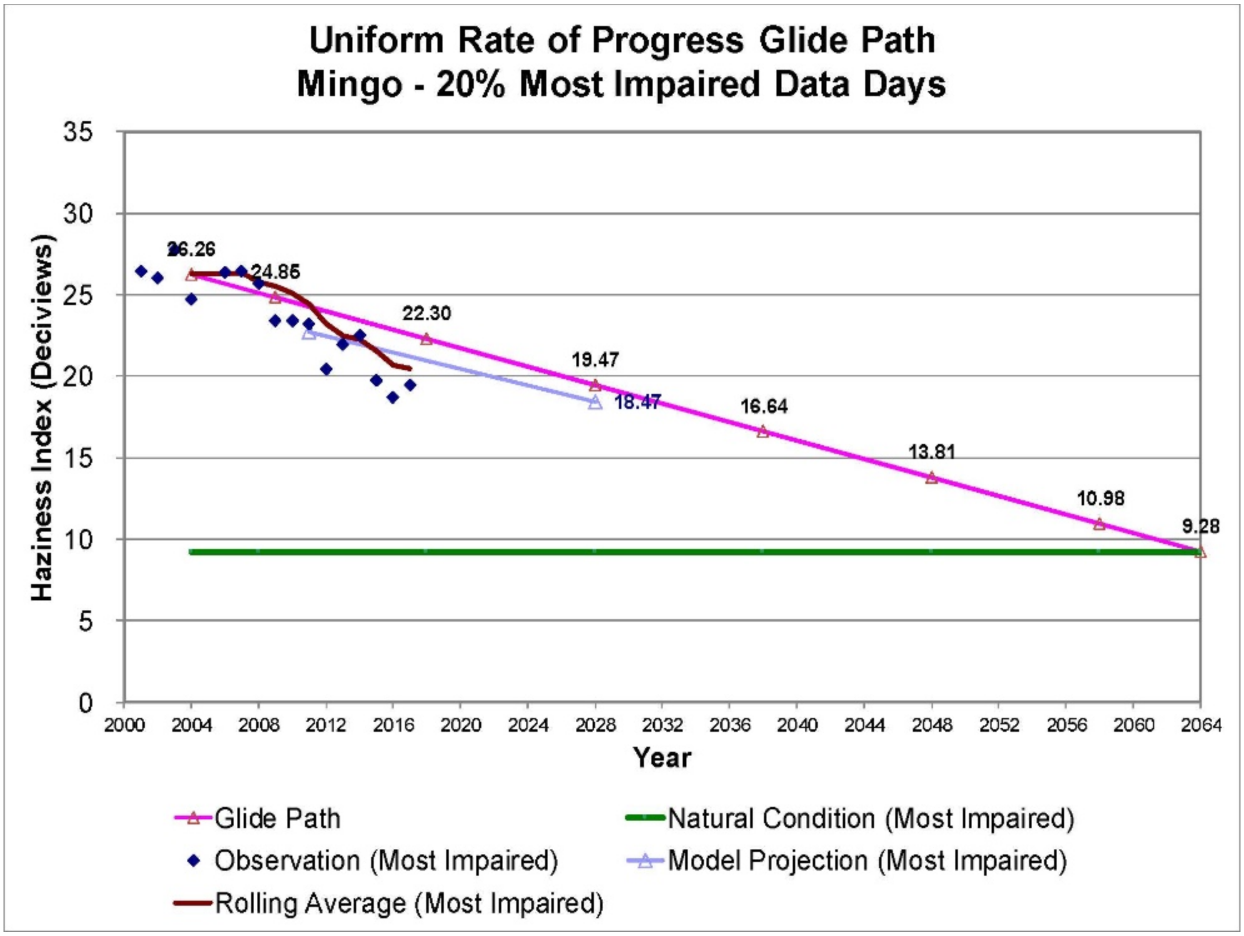

Figure 6-3 Visibility Trend versus URP – Mingo National Wildlife Refuge (568 km)[31]

[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)

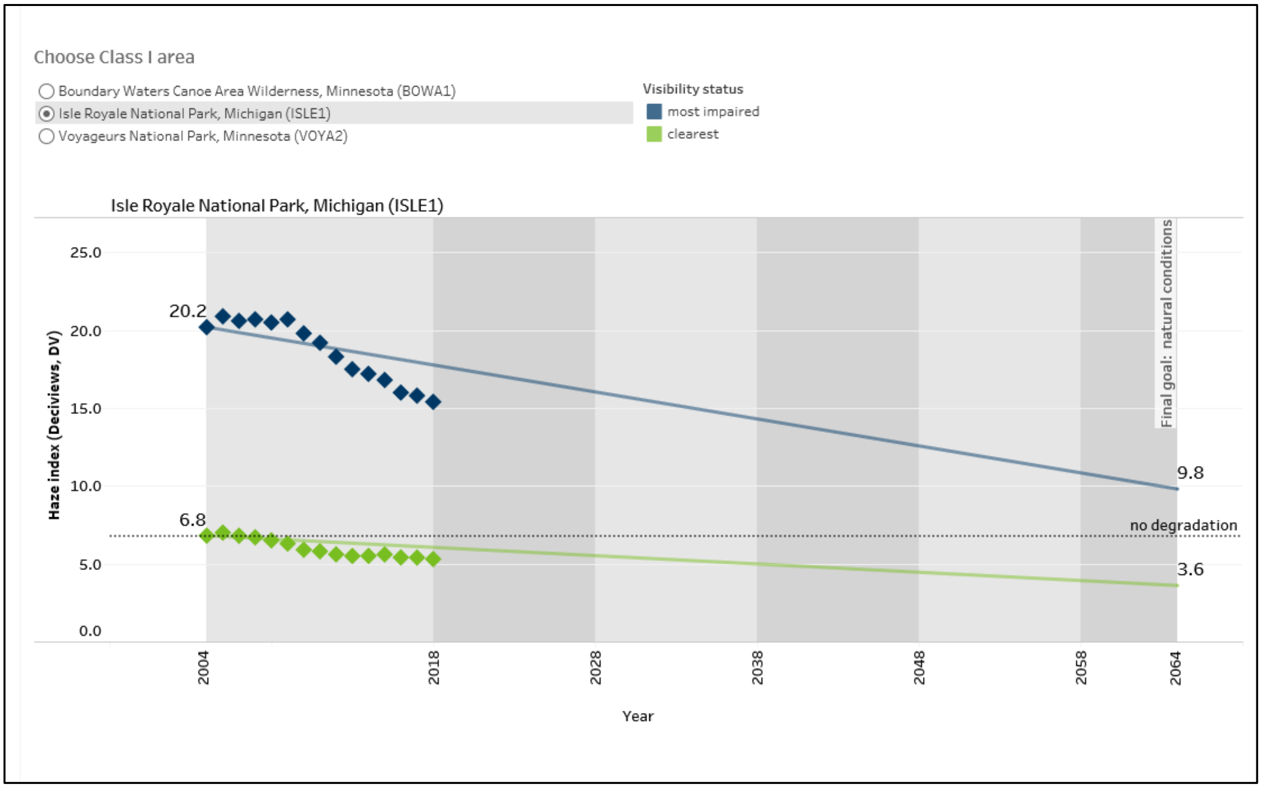

Figure 6-4 Visibility Trend versus URP – Isle Royale National Park (708 km)[32]

[32] Visibility trend from the Minnesota Pollution Control Agency website (https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress)

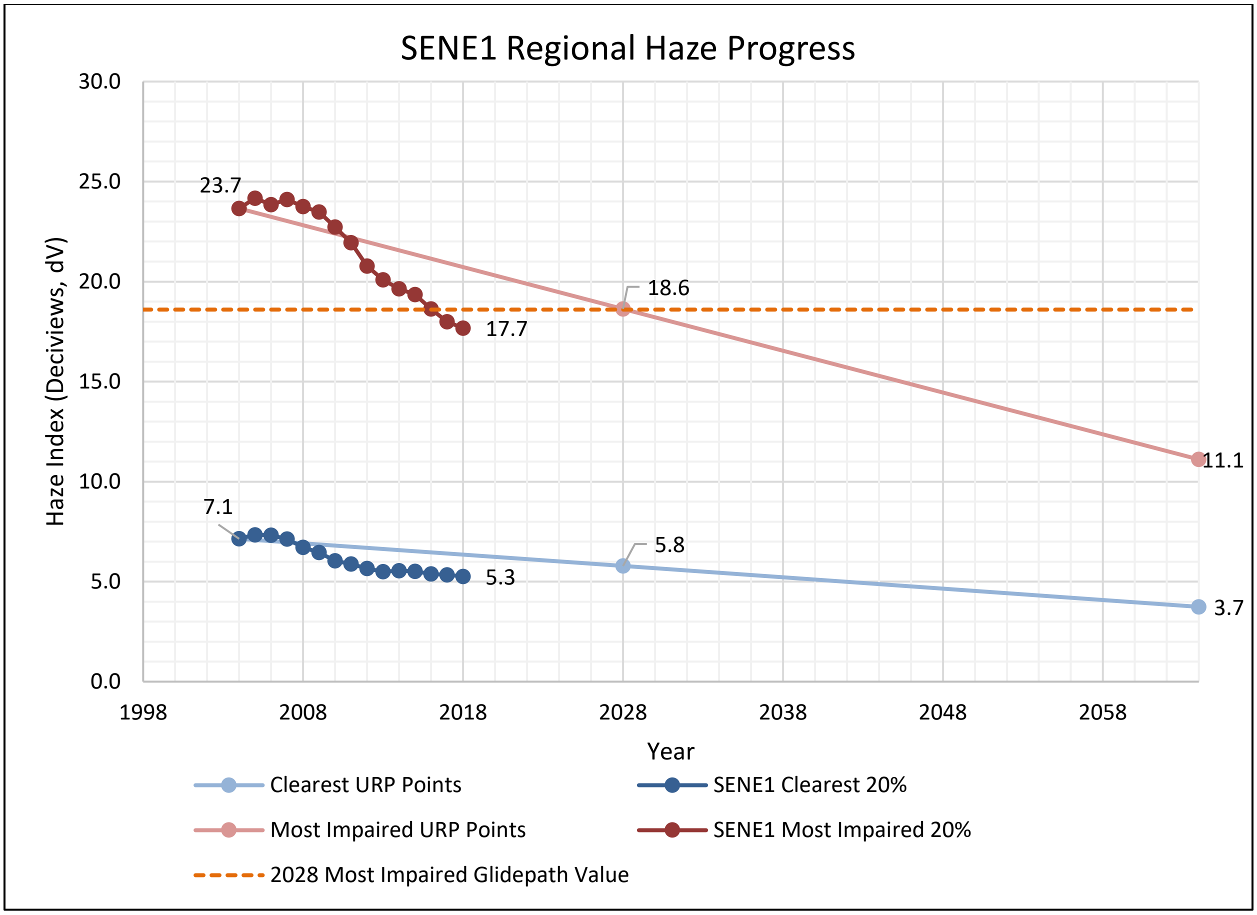

Figure 6-5 Visibility Trend versus URP – Seney National Wildlife Refuge (511 km) [33]

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/)

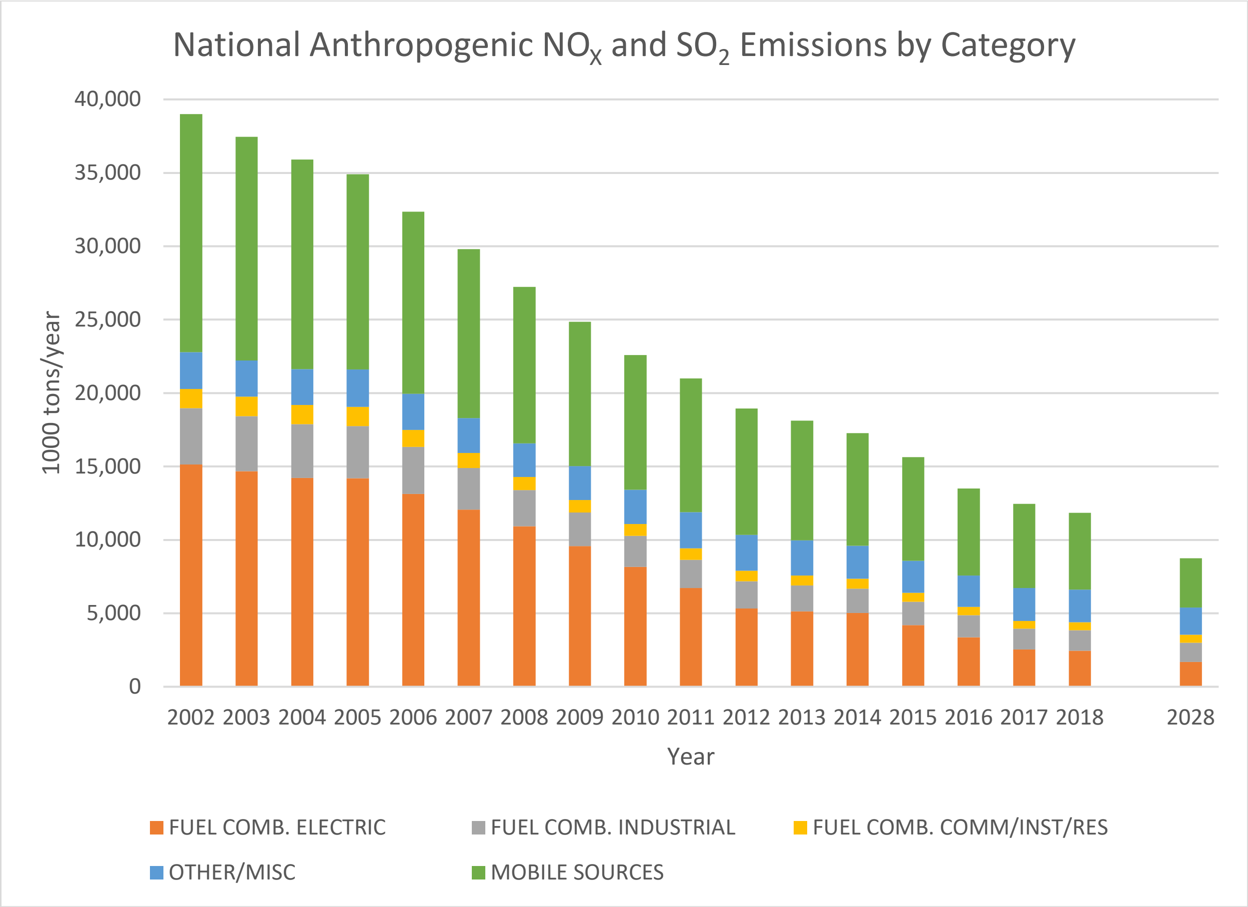

Figure 6-6 National NO_X and SO_2 Emission Trends

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 SO_2 emissions. The emissions from 2002 – 2018 were developed based on information contained in the EPA's Air Pollutant Emission Trends Data[34] and the 2028 data was obtained from page 18 of EPA's regional haze modeling summary which includes the summary of modeled emissions[35].

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[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

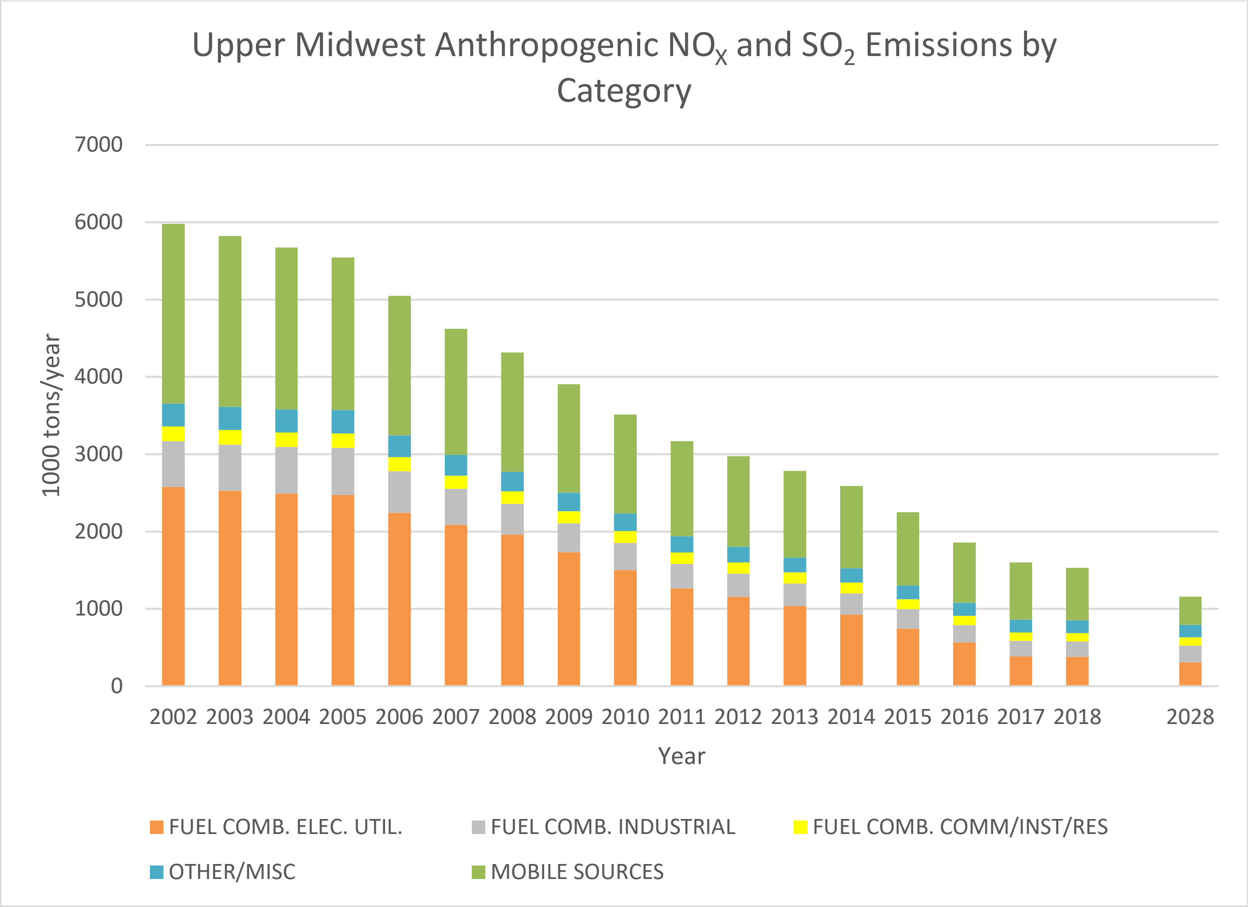

Figure 6-7 Upper Midwest NO_X and SO_2 Emission Trends

The regional summary also exhibits a significant reduction in NO_X and SO_2 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 trends[36] and the 2028 data was obtained from the EPA's 2016v1 modeling platform that also includes 2028 modeling data[37].

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 SO_2 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 SO_2 emission control measures at BH are not required to make reasonable progress in reducing NO_X and SO_2 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

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[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 SO_2 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 perceptible[46] amount to visibility impairment and was exempt from BART.

The current emissions of SO_2 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 VISTAS[47] and CENRAP[48] 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

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[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 website[50]. 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 dataset[51] was used to calculate the 20% most impaired days for 2017 and 2018. The NOAA Hysplit model[52] 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

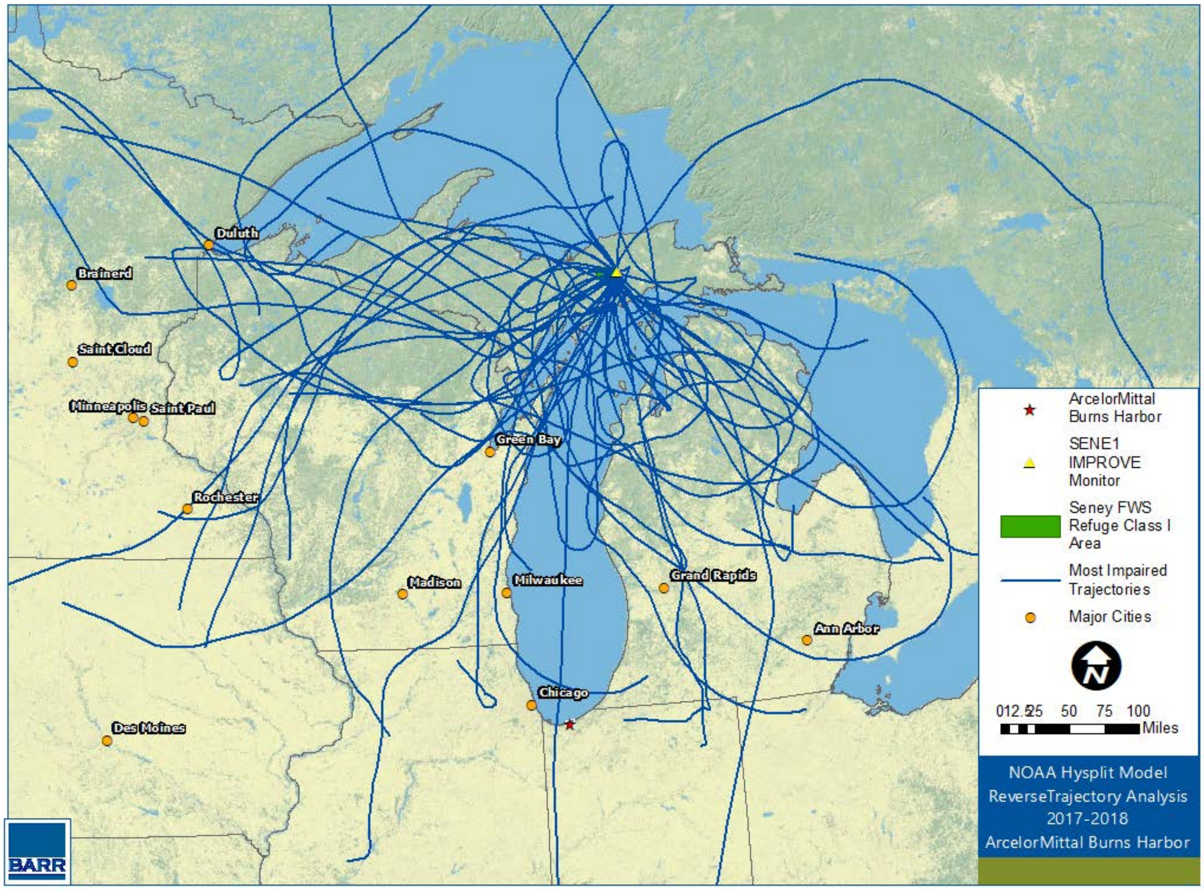
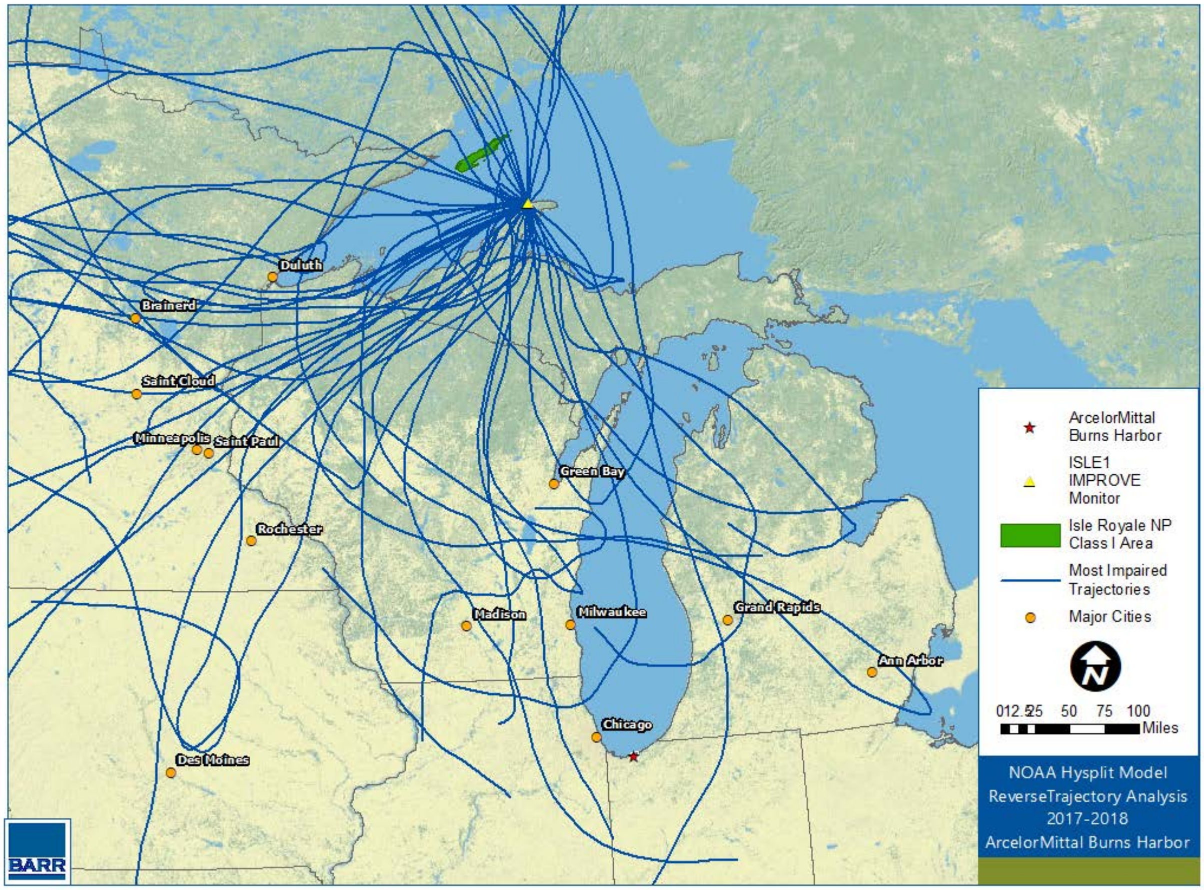


Figure 6–8 **Seney National Wildlife Refuge: Most Impaired Trajectories for 2017-2018 from Reverse Trajectory Analysis**



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 SO_2 emission control measures beyond what is currently installed and operated for these emission units consists of spray dryer absorbers[4] or a coke oven gas desulfurization plant[5].
- The associated SO_2 cost-effectiveness values ($ per ton of emissions reduction) of the reasonable set of additional SO_2 emission control measures are not reasonable.
- Independent of the four-factor analysis, additional NO_X and SO_2 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 SO_2 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 SO_2 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 desulfurization[5].

- The associated SO_2 cost-effectiveness value ($ per ton of emissions reduction) of the reasonable set of additional SO_2 emission control measures is not reasonable.

- As described in the Coke Oven Battery Nos. 1 and 2 conclusion above, additional NO_X and SO_2 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 SO_2 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 SO_2 emission control beyond what is currently installed and operated for this emission unit consists of spray dryer absorbers, dry sorbent injection[7] or a coke oven gas desulfurization plant.

- The associated SO_2 cost-effectiveness values ($ per ton of emissions reduction) of the reasonable set of additional SO_2 emission control measures are not reasonable.

- As described in the Coke Oven Battery Nos. 1 and 2 conclusion above, additional NO_X and SO_2 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 SO_2 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 SO_2 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 SO_2 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 SO_2 emission performance are sufficient for the IDEM's regional haze reasonable progress goal.

Appendix A

RBLC Search Summary for Pertinent Emission Units at Similar Sources

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emissions Control
Appendix A: EPA RACT BACT LAER Clearinghouse Data
Coke Battery

Nitrogen Oxides (NOx)

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	COK-111-Coke Battery 1 Flue Gas Desulfurization	Coal	197	T/H	Nitrogen Oxides (NOx)	Staged Combustion in coke oven	153.7	LB/H		BACT-PSD	612.03	T/H		0.71	LB/T	WET COAL
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	COK-211-Coke Battery 2 Flue Gas Desulfurization	coal	197	T/H	Nitrogen Oxides (NOx)	Staged combustion in the coke oven	153.7	LB/H		BACT-PSD	612.03	T/H		0.71	LB/T	WET COAL
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	COK-202 - Coke Battery 2 Coke Pushing		126	T/H	Nitrogen Oxides (NOx)		4.11	LB/H		BACT-PSD	16.38	T/YR		0.019	LB/T	DRY COKE
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	COK-102 - Coke Battery 1 Coke Pushing		126	T/H	Nitrogen Oxides (NOx)		4.11	LB/H		BACT-PSD	16.38	T/YR		0.019	LB/T	DRY COKE
OH-0332	MIDDLETOWN COKE COMPANY	SUN COKE ENERGY, INC.	OH	P0104768	324199	2/9/2010	Heat Recovery Coke Battery: 100 heat recovery coke ovens in 3 batteries: 1 w/ 20 ovens, 2 w/ 40 ovens each. Process includes coal handling, charging, heat recovery coking, pushing, quenching, coke handling and storage. Heat recovery steam generators will recover	Coke Oven Batteries (3) without heat recovery	coal	2300	T/D	Nitrogen Oxides (NOx)	Bypass one HRSG at a time, one stack	20.8	LB/H		LAER	10	T/YR	PER ROLLING 12-MO.PERIOD FOR HRSG BYPASS	0		
OH-0332	MIDDLETOWN COKE COMPANY	SUN COKE ENERGY, INC.	OH	P0104768	324199	2/9/2010	Heat Recovery Coke Battery: 100 heat recovery coke ovens in 3 batteries: 1 w/ 20 ovens, 2 w/ 40 ovens each. Process includes coal handling, charging, heat recovery coking, pushing, quenching, coke handling and storage. Heat recovery steam generators will recover	Coke Oven Batteries (3), bypass lime spray	coal	0		Nitrogen Oxides (NOx)	Bypass control	1	LB/T	PER TON COAL W/SPRAYDRYER/FILTER BYPASS	LAER	6.25	T/YR	AS A ROLLING 12-MONTH SUMMATION	0		
OH-0332	MIDDLETOWN COKE COMPANY	SUN COKE ENERGY, INC.	OH	P0104768	324199	2/9/2010	Heat Recovery Coke Battery: 100 heat recovery coke ovens in 3 batteries: 1 w/ 20 ovens, 2 w/ 40 ovens each. Process includes coal handling, charging, heat recovery coking, pushing, quenching, coke handling and storage. Heat recovery steam generators will recover	Coke Oven Batteries (3) with heat recovery	coal	912500	T/YR	Nitrogen Oxides (NOx)	Staged combustion	104.2	LB/H		LAER	456.25	T/YR	AS A ROLLING 12-MONTH SUMMATION	1	LB/T	PER WET TON OF COAL AS LAER
OH-0332	MIDDLETOWN COKE COMPANY	SUN COKE ENERGY, INC.	OH	P0104768	324199	2/9/2010	Heat Recovery Coke Battery: 100 heat recovery coke ovens in 3 batteries: 1 w/ 20 ovens, 2 w/ 40 ovens each. Process includes coal handling, charging, heat recovery coking, pushing, quenching, coke handling and storage. Heat recovery steam generators will recover	Pushing, Coke Battery with heat recovery-3	coal	912500	T/YR	Nitrogen Oxides (NOx)	work practices	9.5	LB/H		LAER	8.67	T/YR	PER A ROLLING 12 MONTH SUMMATION	0.019	LB/T	PER TON OF COAL CHARGED
MI-0415	EES COKE BATTERY, LLC	EES COKE BATTERY, LLC	MI	51-08C	331111	11/21/2014 ACT	Existing coke oven battery.	EUCOKE-BATTERY	COKE OVEN GAS	1.42	M tons of dry coal charged	Nitrogen Oxides (NOx)	Staged combustion for the battery underfire combustion system, and good combustion practices for bypass bleeder flares and COG flare. Proper operation of the battery for the	1411	T/YR	12-MO ROLLING TIME PERIOD END OF EACH MO	BACT-PSD	563.5	LB/H	HOURLY	0		

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emissions Control
Appendix A: EPA RACT BACT LAER Clearinghouse Data
Coke Battery

Sulfur Dioxide (SO_2)

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RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	COK-111-Coke Battery 1 Flue Gas Desulfurization	Coal	197	T/H	Sulfur Dioxide (SO2)	Maximum content of 1.25% sulfur in the coal. Purchase natural gas containing no more than 2000 grains of sulfur per MM scf	251.62	LB/H		BACT-PSD	1102.1	T/H		0		
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	COK-211-Coke Battery 2 Flue Gas Desulfurization	coal	197	T/H	Sulfur Dioxide (SO2)	Maximum content of 1.25% sulfur in the coal. Purchase natural gas containing no more than 2000 grains of sulfur per MM scf	251.62	LB/H		BACT-PSD	1102.1	T/H		0		
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	COK-202 - Coke Battery 2 Coke Pushing		126	T/H	Sulfur Dioxide (SO2)		21.22	LB/H		BACT-PSD	84.48	T/YR		0.098	LB/T	DRY COKE
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	COK-102 - Coke Battery 1 Coke Pushing		126	T/H	Sulfur Dioxide (SO2)		21.22	LB/H		BACT-PSD	84.48	T/YR		0.098	LB/T DRY COKE	
OH-0332	MIDDLETOWN COKE COMPANY	SUN COKE ENERGY, INC.	OH	P0104768	324199	2/9/2010	Heat Recovery Coke Battery: 100 heat recovery coke ovens in 3 batteries: 1 w/ 20 ovens, 2 w/ 40 ovens each. Process includes coal handling, charging, heat recovery coking, pushing, quenching, coke handling and storage. Heat recovery steam generators will recover	Charging, Coke Oven Batteries (3) with heat recovery	coal	912500	T/YR	Sulfur Dioxide (SO2)		0.15	LB/H		LAER	0.14	T/YR	AS A ROLLING 12-MONTH SUMMATION	0.0003	LB/T	PER TON OF COAL CHARGED* LAER
OH-0332	MIDDLETOWN COKE COMPANY	SUN COKE ENERGY, INC.	OH	P0104768	324199	2/9/2010	Heat Recovery Coke Battery: 100 heat recovery coke ovens in 3 batteries: 1 w/ 20 ovens, 2 w/ 40 ovens each. Process includes coal handling, charging, heat recovery coking, pushing, quenching, coke handling and storage. Heat recovery steam generators will recover	Coke Oven Batteries (3) without heat recovery	coal	2300	T/D	Sulfur Dioxide (SO2)	Bypass one HRSG at a time, one stack	498.33	LB/H		LAER	239.2	T/YR	PER ROLLING 12-MONTHS FOR HRSG BYPASS	0		
OH-0332	MIDDLETOWN COKE COMPANY	SUN COKE ENERGY, INC.	OH	P0104768	324199	2/9/2010	Heat Recovery Coke Battery: 100 heat recovery coke ovens in 3 batteries: 1 w/ 20 ovens, 2 w/ 40 ovens each. Process includes coal handling, charging, heat recovery coking, pushing, quenching, coke handling and storage. Heat recovery steam generators will recover	Coke Oven Batteries (3), bypass lime spray	coal	0		Sulfur Dioxide (SO2)	During the bypass of the spray dryer the charge size shall be reduced by 28% or the sulfur in coal reduced by 28%	1794	LB/H	FROM BYPASS TO SPRAY DRYER/BAGHOUSE	LAER	107.64	T/YR	AS A ROLLING 12-MONTH SUMMATION	0		
OH-0332	MIDDLETOWN COKE COMPANY	SUN COKE ENERGY, INC.	OH	P0104768	324199	2/9/2010	Heat Recovery Coke Battery: 100 heat recovery coke ovens in 3 batteries: 1 w/ 20 ovens, 2 w/ 40 ovens each. Process includes coal handling, charging, heat recovery coking, pushing, quenching, coke handling and storage. Heat recovery steam generators will recover	Coke Oven Batteries (3) with heat recovery	coal	912500	T/YR	Sulfur Dioxide (SO2)	Fabric filter, common tunnel afterburner maintained at 1400 degrees F, lime spray dryer.	300	LB/H	BASED ON 3-HR BLOCK AVERAGE	LAER	700.8	T/YR	AS A ROLLING 12-MONTH SUMMATION	1.54	LB/T	PER WET TON OF COAL
OH-0332	MIDDLETOWN COKE COMPANY	SUN COKE ENERGY, INC.	OH	P0104768	324199	2/9/2010	Heat Recovery Coke Battery: 100 heat recovery coke ovens in 3 batteries: 1 w/ 20 ovens, 2 w/ 40 ovens each. Process includes coal handling, charging, heat recovery coking, pushing, quenching, coke handling and storage. Heat recovery steam generators will recover	Pushing, Coke Battery with heat recovery-3	coal	912500	T/YR	Sulfur Dioxide (SO2)	work practices	49	LB/H		LAER	44.71	T/YR	PER A ROLLING 12 MONTH SUMMATION	0.098	LB/T	PER TON OF COAL CHARGED

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emissions Control
Appendix A: EPA RACT BACT LAER Clearinghouse Data
Flares in the Ferrous Metals Industry

Nitrogen Oxides (NOx)

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RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
AL-0275	NUCOR STEEL TUSCALOOSA, INC.	NUCOR STEEL TUSCALOOSA, INC.	AL	413-0033	331111	07/22/2014 ACT	Nucor Steel Tuscaloosa, Inc. owns and operates a scrap steel mill. The mill pruduces steel coils.	Vacuum Degasser with flare and cooling towers		0		Nitrogen Oxides (NOx)	Flare	0.005	LB/T		BACT-PSD	0			0		
AR-0150	NUCOR YAMATO STEEL COMPANY (LIMITED PARTNERSHIP)	NUCOR YAMATO STEEL COMPANY (LIMITED PARTNERSHIP)	AR	0883-AOP-R15	331111	06/01/2018 ACT	Nucor-Yamato Steel Company (NYS) owns and operates a steel mill located in Blytheville, AR.	Vacuum tank Degasser and Flare	Natural gas	150	tons per hour	Nitrogen Oxides (NOx)	Proper equipment design and operation	0.098	LB/MMBTU		BACT-PSD	0			0		

Flares in the Ferrous Metals Industry

Sulfur Dioxide (SO_2)

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RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
AR-0150	NUCOR YAMATO STEEL COMPANY (LIMITED PARTNERSHIP)	NUCOR YAMATO STEEL COMPANY (LIMITED PARTNERSHIP)	AR	0883-AOP-R15	331111	06/01/2018 ACT	Nucor-Yamato Steel Company (NYS) owns and operates a steel mill located in Blytheville, AR.	Vacuum tank Degasser and Flare	Natural gas	150	tons per hour	Sulfur Dioxide (SO2)	Proper equipment design and operation	0.0006	LB/MMBTU		BACT-PSD	0			0		

Nitrogen Oxides (NOx)

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RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
*LA-0346	GULF COAST METHANOL COMPLEX	IGP METHANOL LLC	LA	PSD-LA-820	325199	01/04/2018 ACT	proposed facility to produce 20,000 metric tons of methanol per day	Auxiliary Boiler	natural gas	773	mm btu/hr	Nitrogen Oxides (NOx)	LNB + FGR	0			BACT-PSD	0			0		
MD-0044	COVE POINT LNG TERMINAL	DOMINION COVE POINT LNG, LP	MD	PSC CASE NO. 9318	221119	06/09/2014 ACT	LIQUIFIED NATURAL GAS PROCESSING FACILITY AND 130 MEGAWATT GENERATING STATIONFACILITY-WIDE PM10 EMISSION LIMIT = 124.2 TONS/YR FACILITY-WIDE PM2.5 EMISSION LIMIT= 124/2 TONS/YR	2 AUXILLARY BOILERS	PROCESS GAS	435	MMBTU/H	Nitrogen Oxides (NOx)	EXCLUSIVE USE OF FACILITY PROCESS FUEL GAS DURING NORMAL OPERATION AND USE OF A POST-COMBUSTION SCR SYSTEM AND LOW-NOX BURNERS	0.0099	LB/MMBTU	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD	LAER	2946.2	LB/EVENT	FOR ALL STARTUPS	0		
AK-0083	KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	AQ0083CPT06	325311	01/06/2015 ACT	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American	Three (3) Package Boilers	Natural Gas	243	MMBTU/H	Nitrogen Oxides (NOx)	Ultra Low NOx Burners	0.01	LB/MMBTU	30-DAY AVERAGE	BACT-PSD	0			0		
TX-0656	GAS TO GASOLINE PLANT	NATGASOLINE	TX	PSDTX1340 AND 107764	325199	05/16/2014 ACT	Chemical Plant	Boiler	natural gas and fuel gas	950	MMBTU/H	Nitrogen Oxides (NOx)	SCR	0.01	LB/MMBTU		BACT-PSD	0			0		
TX-0659	DEER PARK PLANT	ROHM AND HAAS TEXAS INC	TX	PSDTX1320, 2165	325188	12/20/2013 ACT		Boiler	Natural gas	515	MMBTU/H	Nitrogen Oxides (NOx)	Selective catalytic reduction	0.01	LB/MMBTU	1-HR	BACT-PSD	0			0		
TX-0698	BAYPORT COMPLEX	AIR LIQUIDE LARGE INDUSTRIES U.S., L.P.	TX	9346 PSDTX612M2	325120	09/05/2013 ACT	Air Liquid currently operates a cogeneration facility in Pasadena, Texas (Bayou Cogeneration Plant). The permit amendment submitted by Air Liquide will authorize a redevelopment project of its cogeneration plant. The proposed project will involve the	(3) gas-fired boilers	natural gas	550	MMBTU/H	Nitrogen Oxides (NOx)	Selective Catalytic Reduction (SCR)	0.01	LB/MMBTU	3 HOUR ROLLING AVERAGE	BACT-PSD	0			0		
TX-0704	UTILITY PLANT	M & G RESINS USA LLC	TX	108819 PSDTX1354	221112	12/02/2014 ACT	In support of the new PET (polyethylene terephthalate) unit and new PTA (terephthalic acid) plant proposed by M&G Resins USA LLC, the company also proposes a Utility Plant that will consist of either one of two options. All steam generated from the Utility Plant	(2) boilers	natural gas	450	MMBTU/H	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	0.01	LB/MMBTU	3-HR ROLLING AVERAGE	BACT-PSD	0			0		
TX-0704	UTILITY PLANT	M & G RESINS USA LLC	TX	108819 PSDTX1354	221112	12/02/2014 ACT	In support of the new PET (polyethylene terephthalate) unit and new PTA (terephthalic acid) plant proposed by M&G Resins USA LLC, the company also proposes a Utility Plant that will consist of either one of two options. All steam generated from the Utility Plant	boiler	natural gas	250	MMBTU/H	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	0.01	LB/MMBTU	3-HR ROLLING AVERAGE	BACT-PSD	0			0		
TX-0707	CHEMICAL MANUFACTURING FACILITY	ROHM AND HAAS TEXAS INCORPORATED	TX	2165 PSDTX1320	325110	12/20/2013 ACT	RH is proposing to install two 515 million British thermal unit per hour (MMBtu/hr) gas-fired boilers to produce additional steam for the RH Texas Deer Park Plant manufacturing facilities and give the plant the ability to perform planned maintenance on other steam	(2) boilers	natural gas	515	MMBTU/H	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	0.01	LB/MMBTU	1 HOUR	BACT-PSD	0			0		
WY-0074	GREEN RIVER SODA ASH PLANT	SOLVAY CHEMICALS	WY	MD-13083	212391	11/18/2013 ACT	Trona Mine and Refinery	Natural Gas Package Boiler	Natural Gas	254	MMBTU/H	Nitrogen Oxides (NOx)	low NOx burners and flue gas recirculation	0.011	LB/MMBTU	30-DAY ROLLING	BACT-PSD	2.8	LB/H	30-DAY ROLLING	0		
*FL-0330	PORT DOLPHIN ENERGY LLC		FL	DPA-EPA-R4001	213112	12/01/2011 ACT	Port Dolphin is a deepwater port designed to moor liquefied natural gas shuttle and regasification vessels 28 miles off the cost of Florida.	Boilers (4 - 278 mmbtu/hr each)	natural gas	0		Nitrogen Oxides (NOx)	Selective Catalytic Reduction (SCR)	0.012	LB/MMBTU	3-HOUR ROLLING AVERAGE	BACT-PSD	0			0		
IL-0114	CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	13060007	325311	09/05/2014 ACT	Plant will produce urea and ammonia, but ammonia production will be limited to a maximum of 3 months of the year (4,880 tpd urea and 2,789 tpd ammonia).	Boiler	natural gas	864	MMBTU/H	Nitrogen Oxides (NOx)	low-nox burners, scr (or equivalent)	0.012	LB/MMBTU	30-DAY AVERAGE ROLLED DAILY	BACT-PSD	0			0		
IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	IA	12-219	325311	10/26/2012 ACT	NITROGENEOUS FERTILIZER MANUFACTURING	Auxiliary Boiler	natural gas	472.4	MMBTU/H	Nitrogen Oxides (NOx)	Low NOx Burners (LNB) and Flue Gas Recirculation (FGR)	0.0125	LB/MMBTU	ROLLING 30 DAY AVERAGE	BACT-PSD	5.52	TONS/YR	ROLLING 12 MONTH TOTAL	0		
IN-0166	INDIANA GASIFICATION, LLC	INDIANA GASIFICATION, LLC	IN	T147-30464-00060	221210	06/27/2012 ACT	THE PERMITTEE OWNS AND OPERATES A STATIONARY SUBSTITUTE NATURAL GAS (SNG) AND LIQUEFIED CARBON DIOXIDE (CO2) PRODUCTION PLANT	TWO (2) AUXILIARY BOILERS	NATURAL GAS	408	MMBTU/H, EACH	Nitrogen Oxides (NOx)	ULTRA LOW NOX BURNER WITH FGR	0.0125	LB/MMBTU	24 HR	BACT-PSD	0			0		
LA-0305	LAKE CHARLES METHANOL FACILITY	LAKE CHARLES METHANOL, LLC	LA	PSD-LA-803(M1)	325199	06/30/2016 ACT	Proposed facility to produce methanol, H2, H2SO4, CO2, Argon and electricity from Pet Coke	Auxiliary Boilers and Superheaters	Natural Gas	0		Nitrogen Oxides (NOx)	SCR	0.015	LBS/MM BTU	30 ROLLING AVG., EXCEPT SCR SU OR MAINT.	BACT-PSD	0			0		
*TX-0888	ORANGE POLYETHYLENE PLANT	CHEVRON PHILLIPS CHEMICAL COMPANY LP	TX	155952 PSDTX1556 GHGPSDTX192	325211	04/23/2020 ACT	An initial NSR, PSD, and GHG project to construct and operate an Olefins Unit, two Polyethylene (PE) Units, and auxiliary support facilities. This permit will consist of furnaces, boilers, heaters, storage tanks, emergency engines, fugitive piping, thermal oxidizers,	BOILERS	Natural gas, ethane, fuel, or vent gas	250	MMBTU	Nitrogen Oxides (NOx)	SCR	0.015	LB/MMBTU	HOURLY	BACT-PSD	0.01	LB/MMBTU	ANNUAL	0		
DE-0020	VALERO DELAWARE CITY REFINERY	VALERO ENERGY CORP	DE	AQM-003/00016	324110	02/26/2010 ACT	191,100 BARREL PER DAY REFINERY AKA THE PREMCOR REFINING GROUP INC.	PACKAGE BOILERS (2009)	REFINERY FUEL GAS	99.9	MMBtu per hour	Nitrogen Oxides (NOx)	SCR AND LOW NOX BURNERS	0.015	LB/MMBTU		RACT	0			0		
DE-0020	VALERO DELAWARE CITY REFINERY	VALERO ENERGY CORP	DE	AQM-003/00016	324110	02/26/2010 ACT	191,100 BARREL PER DAY REFINERY AKA THE PREMCOR REFINING GROUP INC.	DCPP BOILER 1	REFINERY FUEL GAS	618	MMBTU/H	Nitrogen Oxides (NOx)	SCR WITH MODIFICATIONS TO EXISTING BURNERS AND AIR DISTRIBUTION TO BURNERS, OPTIMIZATION TO OVER-FIRE AIR SYSTEMS, INSTALLATION OF INDUCED FLUE	0.015	LB/MMBTU	24-HOUR ROLLING AVERAGE	BACT-PSD	40.6		12-MONTHS	0		
DE-0020	VALERO DELAWARE CITY REFINERY	VALERO ENERGY CORP	DE	AQM-003/00016	324110	02/26/2010 ACT	191,100 BARREL PER DAY REFINERY AKA THE PREMCOR REFINING GROUP INC.	DCPP BOILER 3	REFINERY FUEL GAS	618	MMBTU/H	Nitrogen Oxides (NOx)	SCR WITH MODIFICATIONS TO EXISTING BURNERS AND AIR DISTRIBUTION TO BURNERS, OPTIMIZATION TO OVER-FIRE AIR SYSTEMS, INSTALLATION OF INDUCED FLUE	0.015	LB/MMBTU	24-HOUR ROLLING AVERAGE	BACT-PSD	40.6	T	12-MONTHS	0		
TX-0763	BORGER REFINERY	PHILLIPS 66 COMPANY	TX	85872, PSDTX1158M1, GHGPSDTX13	324110	09/04/2015 ACT	The refinery processes crude oil and other feedstocks into products including gasoline, furnace oil, jet fuels, kerosene, petrochemicals, and blendstocks for liquid fuels.	Utility and Industrial Boiler greater than 250 million British	refinery fuel	560	MMBTU/H	Nitrogen Oxides (NOx)	SCR	0.015	LB/MMBTU		BACT-PSD	0			0		
TX-0763	BORGER REFINERY	PHILLIPS 66 COMPANY	TX	85872, PSDTX1158M1, GHGPSDTX13	324110	09/04/2015 ACT	The refinery processes crude oil and other feedstocks into products including gasoline, furnace oil, jet fuels, kerosene, petrochemicals, and blendstocks for liquid fuels.	Utility and Industrial Boiler greater than 250 million British	refinery fuel	364.6	MMBTU/H	Nitrogen Oxides (NOx)	selective catalytic reduction (SCR)	0.015	LB/MMBTU		BACT-PSD	0			0		
ND-0032	SPIRITWOOD NITROGEN PLANT	CHS, INC.	ND	PTC14027	325311	06/20/2014 ACT	Fertilizer manufacturing plant to manufacture nitrogen-based products ammonia, urea, urea ammonium nitrate (UAN) and diesel exhaust fluid. The facility will produce both feedstock and saleable products in the following capacities: 2,425 tpd ammonia; 3,000 tpd	Package boiler	Natural gas	280	MMBTU/H	Nitrogen Oxides (NOx)	ultra low NOx burners and flue gas recirculation	0.018	LB/MMBTU	30 DAY ROLLING AVERAGE	BACT-PSD	0			0		
*ND-0033	GRAND FORKS FERTILIZER PLANT	NORTHERN PLAINS NITROGEN	ND	PTC15052	325311	08/10/2015 ACT	Fertilizer manufacturing plant designed to produce both feedstock and saleable products in the following nominal capacities: 2425 tpd ammonia, 2540 tpd ammonium nitrate solution, 300 tpd DEF, 3000 tpd urea solution, 3000 tpd granular urea, 2000 tpd nitric acid, 5620	Boilers	Natural gas	187.5	MMBTU/H	Nitrogen Oxides (NOx)	Ultra Low NOx Burners and Flue Gas Recirculation	0.018	LB/MM BTU	30 DAY ROLLING AVERAGE	BACT-PSD	0			0		
AL-0271	GEORGIA PACIFIC BRETON LLC	GEORGIA PACIFIC LLC	AL	502-0001-X049	322130	06/11/2014 ACT	Kraft Pulp & Paper mdu	No.4 Power Boiler	Natural Gas	425	MMBTU/H	Nitrogen Oxides (NOx)	Low NOx Burner with FGR	0.02	LB/MMBTU		BACT-PSD	8.5	LB/H		0		
DE-0020	VALERO DELAWARE CITY REFINERY	VALERO ENERGY CORP	DE	AQM-003/00016	324110	02/26/2010 ACT	191,100 BARREL PER DAY REFINERY AKA THE PREMCOR REFINING GROUP INC.	PACKAGE BOILERS (2004)	REFINERY FUEL GAS	216	MMBtu per hour	Nitrogen Oxides (NOx)		0.02	LB/MMBTU	3-HR AVERAGE	RACT	24.9	T	12 MONTHS	0		
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	OH	P0124972	325110	12/21/2018 ACT	Petrochemical Complex	Natural Gas and Ethane-Fired Steam Boilers (B007 - B009)	Natural gas and ethane	400	MMBTU/H	Nitrogen Oxides (NOx)	ultra-low NOx burners (ULNB) and flue gas recirculation (FGR)	0.02	LB/MMBTU	DURING STARTUP AND SHUTDOWN. SEE NOTES.	BACT-PSD	4	LB/H	AS ROLLING 30-DAY AVG. SEE NOTES.	0.01	LB/MMBTU	AS ROLLING 30-DAY AVG. SEE NOTES.
TX-0776	BISHOP FACILITY	TICONA POLYMERS, INC.	TX	123077, PSDTX1436, AND GHGPSDT	324199	11/12/2015 ACT	The three new boilers will provide steam to existing steam users at the Bishop Site and to a new Methanol Unit Project proposed in a concurrent air permit application (Permit No. 123216 and PSDTX1438). The new Boiler Project will authorize construction and	Boiler	natural gas	452	MMBTU/H	Nitrogen Oxides (NOx)	Selective Catalytic Reduction, Low NOx Burners, Flue Gas Recirculation	0.02	PPM	1-HR AVG	BACT-PSD	0.01	PPM	ROLLING MONTHLY AVERAGE	0		

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emissions Control
Appendix A: EPA RACT BACT LAER Clearinghouse Data
Gas Fired Boilers

Nitrogen Oxides (NOx)

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RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
FL-0344	OKEELANTA COGENERATION PLANT	NEW HOPE POWER COMPANY	FL	0990332-021-AC	221119	08/27/2013 ACT	Cogeneration facility, fired with bagasse, wood, and natural gas. Four boilers, total electrical generating capacity of 140 MW. Also generates steam for co-located sugar refinery and sugar mill.	Natural Gas Boiler	Natural gas	589	MMBTU/H	Nitrogen Oxides (NOx)	Ultra-low NOx burners with over-fire air	0.035	LB/MMBTU	30-DAY ROLLING AVERAGE BY CEMS	BACT-PSD	18.8	LB/H	30-DAY ROLLING AVERAGE BY CEMS	0		
LA-0323	MONSANTO LULING PLANT	MONSANTO COMPANY	LA	PSD-LA-890	325320	01/09/2017 ACT	Chemical Manufacture	No. 9 Boiler - Natural Gas Fired	Natural Gas	325	MMBTU/h	Nitrogen Oxides (NOx)	Ultra Low NOx Burners	0.035	LB/MMBTU	ANNUAL AVERAGE	BACT-PSD	0			0		
LA-0323	MONSANTO LULING PLANT	MONSANTO COMPANY	LA	PSD-LA-890	325320	01/09/2017 ACT	Chemical Manufacture	No. 10 Boiler - Natural Gas Fired	Natural Gas	325	MMBTU/h	Nitrogen Oxides (NOx)	Ultra Low NOx Burners	0.035	LB/MMBTU	ANNUAL AVERAGE	BACT-PSD	0			0		
*MI-0440	MICHIGAN STATE UNIVERSITY	MICHIGAN STATE UNIVERSITY	MI	139-18	611310	05/22/2019 ACT	New natural gas electric and steam generation.	EUSTMBOILER	natural gas	300	MMBTU/H	Nitrogen Oxides (NOx)	Low-NOx burners and internal flue gas recirculation (FGR)	0.04	LB/MMBTU	30 DAY ROLL AVG WHEN FIRING NAT. GAS	BACT-PSD	0.07	LB/MMBTU	30 DAY ROLL AVG WHEN FIRING NO2 FUEL OIL	0		
NE-0054	CARGILL, INCORPORATED	CARGILL, INCORPORATED	NE	12-042	311221	09/12/2013 ACT		Boiler K	natural gas	300	mmbtu/h	Nitrogen Oxides (NOx)	LOW NOX BURNERS AND INDUCED FLUE GAS RECIRCULATION	0.04	LB/MMBTU	30-DAY ROLLING AVERAGE	BACT-PSD	12	LB/H	3-HOUR ROLLING AVERAGE	0		
TX-0763	BORGER REFINERY	PHILLIPS 66 COMPANY	TX	85872, PSDTX1158M1, GHGPSDTX13	324110	09/04/2015 ACT	The refinery processes crude oil and other feedstocks into products including gasoline, furnace oil, jet fuels, kerosene, petrochemicals, and blendstocks for liquid fuels.	Utility and Industrial Boiler greater than 250 million British	refinery fuel	462.3	MMBTU/H	Nitrogen Oxides (NOx)		0.04	LB/MMBTU		BACT-PSD	0			0		
IN-0234	GRAIN PROCESSING CORPORATION	GRAIN PROCESSING CORPORATION	IN	027-35177-00046	311221	12/08/2015 ACT	THIS FACILITY IS A STATIONARY CORN WET MILLING PLANT.	BOILER 1	NATURAL GAS	271	MMBTU/H	Nitrogen Oxides (NOx)	LOW-NOX BURNER AND FLUE GAS RECIRCULATION SYSTEM	0.05	LB/MMBTU	NORMAL OPERATION	BACT-PSD	0.2	LB/MMBTU	DURING SSM	0		
IN-0234	GRAIN PROCESSING CORPORATION	GRAIN PROCESSING CORPORATION	IN	027-35177-00046	311221	12/08/2015 ACT	THIS FACILITY IS A STATIONARY CORN WET MILLING PLANT.	BOILER 2	NATURAL GAS	271	MMBTU/H	Nitrogen Oxides (NOx)	LOW-NOX BURNERS AND FLUE GAS RECIRCULATION	0.05	LB/MMBTU	NORMAL OPERATION	BACT-PSD	0.2	LB/MMBTU	DURING SSM	0		
OH-0368	PALLAS NITROGEN LLC	PALLAS NITROGEN LLC	OH	P0118959	325311	04/19/2017 ACT	Natural gas-based facility for the manufacture of nitrogenous products.	Package Boilers (2 identical, B003 and B004)	Natural gas	265	MMBTU/H	Nitrogen Oxides (NOx)	Low NOx burners and flu gas recirculation (FGR)	3.3	LB/H		BACT-PSD	14.5	T/YR	PER ROLLING 12 MONTH PERIOD	0.0125	LB/MMBTU	
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	LA	PSD-LA-780(M-1)	325998	06/30/2017 ACT	New MeOH plant designed to produce 5,275 metric tons per day of refined methanol from natural gas and carbon dioxide (CO2) feedstock	B1-13 - Boiler 1 (EQT0003)	Natural Gas	350	MM BTU/hr	Nitrogen Oxides (NOx)	Selective Catalytic Reduction, Low NOx Burners, & Good Combustion Practices	3.5	LB/HR		BACT-PSD	0.01	LB/MMMTU	12 MONTH AVERAGE	0		
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	LA	PSD-LA-780(M-1)	325998	06/30/2017 ACT	New MeOH plant designed to produce 5,275 metric tons per day of refined methanol from natural gas and carbon dioxide (CO2) feedstock	B2-13 - Boiler 2 (EQT0004)	Natural Gas	350	MM BTU/hr	Nitrogen Oxides (NOx)	Selective Catalytic Reduction, Low NOx Burners, & Good Combustion Practices	3.5	LB/HR		BACT-PSD	0.01	LB/MMBTU	12-MONTH AVERAGE	0		
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	PSD-LA-781	325110	05/23/2014 ACT	The G2G Plant will be a natural gas to gasoline production facility which will use natural gas to produce methanol that will be subsequently converted into gasoline.	Utility Boiler 1	Natural Gas	656	MMBTU/HR	Nitrogen Oxides (NOx)	Selective Catalytic Reduction (SCR)	3.94	LB/H	HOURLY MAXIMUM	BACT-PSD	17.25	T/YR	ANNUAL MAXIMUM	0.2	LB/MMBTU	30-DAY ROLLING AVERAGE
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	PSD-LA-781	325110	05/23/2014 ACT	The G2G Plant will be a natural gas to gasoline production facility which will use natural gas to produce methanol that will be subsequently converted into gasoline.	Utility Boiler 2	Natural Gas	656	MMBTU/HR	Nitrogen Oxides (NOx)	Selective Catalytic Reduction (SCR)	3.94	LB/H	HOURLY MAXIMUM	BACT-PSD	17.25	T/YR	ANNUAL MAXIMUM	0.2	LB/MMBTU	30-DAY ROLLING AVERAGE
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	PSD-LA-781	325110	05/23/2014 ACT	The G2G Plant will be a natural gas to gasoline production facility which will use natural gas to produce methanol that will be subsequently converted into gasoline.	Utility Boiler 3	Natural Gas	656	MMBTU/HR	Nitrogen Oxides (NOx)	Selective Catalytic Reduction (SCR)	3.94	LB/H	HOURLY MAXIMUM	BACT-PSD	17.25	T/YR	ANNUAL MAXIMUM	0.2	LB/MMBTU	30-DAY ROLLING AVERAGE
TX-0803	PL PROPYLENE HOUSTON OLEFINS PLANT	FLINT HILLS RESOURCES HOUSTON CHEMICAL LLC	TX	18999, PSDTX755M1, N216	325110	07/12/2016 ACT	catalytic process to produce propylene from propane and mixed propane/propylene feed	Waste Heat Boiler	natural gas	1690	MMBTU/H	Nitrogen Oxides (NOx)	selective catalytic reduction	5	PPMVD @ 15% O2	12-MONTH AVG	LAER	9	PPMVD @ 15% O2	3-HR AVERAGE	0		
AK-0083	KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	AK	AQ0083CPT06	325311	01/06/2015 ACT	The Kenai Nitrogen Operations Facility is located at Mile 21 of the Kenai Spur Highway, near Kenai Alaska. It is classified as a nitrogenous fertilizer manufacturing facility under Standard Industrial Classification code 2873 and under North American	Five (5) Waste Heat Boilers	Natural Gas	50	MMBTU/H	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	7	PPMV	3-HR AVG @ 15 % O2	BACT-PSD	0			0		
CA-1214	GROSSMONT HOSPITAL	GROSSMONT HOSPITAL	CA	2012-APP-002050	622110	11/06/2012 ACT		Two 29.4 MMBtu/hr Boilers with low NOx burners	natural gas	0		Nitrogen Oxides (NOx)	Low NOx burners	9	PPMVD@3% O2	1 HOUR	OTHER CASE-BY-CASE	0			0		
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	THREE (3) AUXILARY BOILERS	NATURAL GAS	218.6	MMBTU/H, EACH	Nitrogen Oxides (NOx)	LOW NOX BURNERS, FLUE GAS RECIRCULATION	20.4	LB/MMCF	3-HR AVERAGE	BACT-PSD	0			0		
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	THREE (3) AUXILARY BOILERS	NATURAL GAS	218.6	MMBTU/H, EACH	Nitrogen Oxides (NOx)	LOW NOX BURNERS, FLUE GAS RECIRCULATION	20.4	LB/MMCF	3-HR AVERAGE	BACT-PSD	0			0		
LA-0288	LAKE CHARLES CHEMICAL COMPLEX	SASOL CHEMICALS (USA) LLC	LA	PSD-LA-778	325110	05/23/2014 ACT		HP SH Steam Boilers (EQT 631, 632, & 633)	PROCESS GAS	408.4	MM BTU/HR	Nitrogen Oxides (NOx)	Ultra low NOx burners (ULNBs) and selective catalytic reduction (SCR)	20.59	LB/HR	HOURLY MAXIMUM	BACT-PSD	11.33	TPY	ANNUAL MAXIMUM	0.01	LB/MMBTU	30-DAY ROLLING AVERAGE
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	SASOL CHEMICALS (USA) LLC	LA	PSD-LA-779	325110	05/23/2014 ACT		Utility Steam Boiler Nos. 1-3 (EQTs 967, 968, & 969)	Process Gas	662	MM BTU/HR	Nitrogen Oxides (NOx)	Selective catalytic reduction (SCR) and ultra low NOx burners (ULNB)	33.7	LB/HR	HOURLY MAXIMUM	BACT-PSD	70.96	TPY*	ANNUAL MAXIMUM	0.01	LB/MMBTU	30-DAY ROLLING AVERAGE

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Gas Fired Boilers

Sulfur Dioxide (SO_2)

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RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
LA-0288	LAKE CHARLES CHEMICAL COMPLEX	SASOL CHEMICALS (USA) LLC	LA	PSD-LA-778	325110	05/23/2014 ACT		HP SH Steam Boilers (EQT 631, 632, & 633)	PROCESS GAS	408.4	MM BTU/HR	Sulfur Dioxide (SO2)	Use of gaseous fuels with a sulfur content no more than 0.005 gr/scf	24.22	LB/HR	HOURLY MAXIMUM	BACT-PSD	1.67	TPY	ANNUAL MAXIMUM	0		
LA-0301	LAKE CHARLES CHEMICAL COMPLEX ETHYLENE 2 UNIT	SASOL CHEMICALS (USA) LLC	LA	PSD-LA-779	325110	05/23/2014 ACT		Utility Steam Boiler Nos. 1-3 (EQTs 967, 968, & 969)	Process Gas	662	MM BTU/HR	Sulfur Dioxide (SO2)	Use of gaseous fuels with a sulfur content of no more than 0.005 grains per standard cubic foot (annual average)	1.98	LB/HR	HOURLY MAXIMUM	BACT-PSD	10.43	TPY*	ANNUAL MAXIMUM	0		
*FL-0330	PORT DOLPHIN ENERGY LLC		FL	DPA-EPA-R4001	213112	12/01/2011 ACT	Port Dolphin is a deepwater port designed to moor liquefied natural gas shuttle and regasification vessels 28 miles off the cost of Florida.	Boilers (4 - 278 mmbtu/hr each)	natural gas	0		Sulfur Dioxide (SO2)	use of natural gas	0.0006	LB/MMBTU	3-HOUR ROLLING AVERAGE	BACT-PSD	0			0		
IN-0166	INDIANA GASIFICATION, LLC	INDIANA GASIFICATION, LLC	IN	T147-30464-00060	221210	06/27/2012 ACT	THE PERMITTEE OWNS AND OPERATES A STATIONARY SUBSTITUTE NATURAL GAS (SNG) AND LIQUEFIED CARBON DIOXIDE (CO2) PRODUCTION PLANT	TWO (2) AUXILIARY BOILERS	NATURAL GAS	408	MMBTU/H, EACH	Sulfur Dioxide (SO2)	USE OF NATURAL GAS OR SNG	0.0006	MMBTU/H	3 HR	BACT-PSD	0			0		
IN-0234	GRAIN PROCESSING CORPORATION	GRAIN PROCESSING CORPORATION	IN	027-35177-00046	311221	12/08/2015 ACT	THIS FACILITY IS A STATIONARY CORN WET MILLING PLANT.	BOILER 1	NATURAL GAS	271	MMBTU/H	Sulfur Dioxide (SO2)	SULFUR CONTENT OF ALCOHOL AND BY-PRODUCT WASTE OIL	0.0006	LB/MMBTU	NATURAL GAS ALONE	BACT-PSD	0.0008	LB/MMBTU	NATURAL GAS AND ALCOHOL	0		
LA-0305	LAKE CHARLES METHANOL FACILITY	LAKE CHARLES METHANOL, LLC	LA	PSD-LA-803(M1)	325199	06/30/2016 ACT	Proposed facility to produce methanol, H2, H2SO4, CO2, Argon and electricity from Pet Coke	Auxiliary Boilers and Superheaters	Natural Gas	0		Sulfur Dioxide (SO2)	fuel gases and/or pipeline quality natural gas	0			BACT-PSD	0			0		
*TX-0888	ORANGE POLYETHYLENE PLANT	CHEVRON PHILLIPS CHEMICAL COMPANY LP	TX	155952 PSDTX1556 GHGPSDTX192	325211	04/23/2020 ACT	An initial NSR, PSD, and GHG project to construct and operate an Olefins Unit, two Polyethylene (PE) Units, and auxiliary support facilities. This permit will consist of furnaces, boilers, heaters, storage tanks, emergency engines, fugitive piping, thermal oxidizers,	BOILERS	Natural gas, ethane, fuel, or vent gas	250	MMBTU	Sulfur Dioxide (SO2)	Good combustion practice and clean fuel	2	GR/100 SCF		BACT-PSD	0			0		

Nitrogen Oxides (NOx)

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LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	SLG-104 - Blast Furnace 1 Slag Pit 1		28.66	T/H	Nitrogen Oxides (NOx)		0.71	LB/H		BACT-PSD	0.47	T/YR		0.0248	LB/T OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	SLG-105 - Blast Furnace 1 Slag Pit 2		28.66	T/H	Nitrogen Oxides (NOx)		0.71	LB/H		BACT-PSD	0.47	T/YR		0.0248	LB/T OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	SLG-106 - Blast Furnace 1 Slag Pit 3		28.66	T/H	Nitrogen Oxides (NOx)		0.71	LB/H		BACT-PSD	0.47	T/YR		0.0248	LB/T OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	SLG-204 - Blast Furnace 2 Slag Pit 1		28.66	T/h	Nitrogen Oxides (NOx)		0.71	LB/H		BACT-PSD	0.47	T/YR		0.0248	LB/T OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	SLG-205 - Blast Furnace 2 Slag Pit 2		28.66	t/h	Nitrogen Oxides (NOx)		0.71	LB/H		BACT-PSD	0.47	T/YR		0.0248	LB/TON OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	SLG-206 - Blast Furnace 2 Slag Pit 3		28.66	t/h	Nitrogen Oxides (NOx)		0.71	LB/H		BACT-PSD	0.47	T/YR		0.0248	LB/TON OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	05/24/2010 ACT	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	STV-101-Blast Furnace 1 Hot Blast Stoves Common Stack	Blast Furnace Gas	627.04	MMBTU/H	Nitrogen Oxides (NOx)	Low-NOx fuel combustion	66.29	LB/H		BACT-PSD	161.23	T/YR		0.06	LB/MMBTU	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	05/24/2010 ACT	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	STV-201-Blast Furnace 2 Hot Blast Stoves Common Stack	Blast Furnace Gas	627.04	MMBTU/H	Nitrogen Oxides (NOx)	Low-NOx fuel combustion	66.29	LB/H		BACT-PSD	161.23	T/YR		0.06	LB/MMBTU	

Sulfur Dioxide (SO_2)

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	SLG-104 - Blast Furnace 1 Slag Pit 1		28.66	T/H	Sulfur Dioxide (SO2)		3.28	LB/H		BACT-PSD	2.16	T/YR		0.115	LB/ OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	SLG-105 - Blast Furnace 1 Slag Pit 2		28.66	T/H	Sulfur Dioxide (SO2)		3.28	LB/H		BACT-PSD	2.16	T/YR		0.115	LB/T OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	SLG-106 - Blast Furnace 1 Slag Pit 3		28.66	T/H	Sulfur Dioxide (SO2)		3.28	LB/H		BACT-PSD	2.16	T/YR		0.115	LB/T OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	SLG-204 - Blast Furnace 2 Slag Pit 1		28.66	T/h	Sulfur Dioxide (SO2)		3.28	LB/H		BACT-PSD	2.16	T/YR		0.115	LB/TON OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	SLG-205 - Blast Furnace 2 Slag Pit 2		28.66	t/h	Sulfur Dioxide (SO2)		3.28	LB/H		BACT-PSD	2.16	T/YR		0.115	LB/TON OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	SLG-206 - Blast Furnace 2 Slag Pit 3		28.66	t/h	Sulfur Dioxide (SO2)		3.28	LB/H		BACT-PSD	2.16	T/YR		0.115	LB/T OF SLAG	
MI-0377	SEVERSTAL NORTH AMERICA, INC.	SEVERSTAL NORTH AMERICA, INC.	MI	182-05	331111	1/31/2006	INTEGRATED IRON AND STEEL PLANT	BLAST FURNACE STOVES	BLAST FURNACE GAS	24003	MMSCF/YR	Sulfur Dioxide (SO2)	NO CONTROLS FEASIBLE. COMPLIANCE VERIFICATION VIA CEMS.	14.37	LB/MMMSCF	WHEN B FURNACE OPERATING	BACT-PSD	16.62	LB/MMSCF	WHEN B FURNACE NOT OPERATING	0		
MI-0413	AK STEEL	AK STEEL CORPORATION	MI	182-05C	331111	5/12/2014	Iron and steel manufacturing facility	EUCFURNACE - C Blast Furnace which includes the blast furnace	Nat. gas, BFG, pulv coal, coke	37841	MMCF/YR	Sulfur Dioxide (SO2)		179.65	LB/H	CALENDAR DAY AVG; BAGHOUSE STACK	BACT-PSD	193.6	LB/H	CALENDAR DAY AVG; STOVE STACK	0		
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	05/24/2010 ACT	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	STV-101-Blast Furnace 1 Hot Blast Stoves Common Stack	Blast Furnace Gas	627.04	MMBTU/H	Sulfur Dioxide (SO2)	No feasible control technology for Blast Furnace Gas. (BFG) Limit Natural Gas sulfur content	19.54	LB/H		BACT-PSD	28.19	T/YR		0		
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	05/24/2010 ACT	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON	STV-201-Blast Furnace 2 Hot Blast Stoves Common Stack	Blast Furnace Gas	627.04	MMBTU/H	Sulfur Dioxide (SO2)	No feasible control technology for Blast Furnace Gas. (BFG) Limit Natural Gas sulfur content	19.54	LB/H		BACT-PSD	28.19	T/H		0		
MI-0377	SEVERSTAL NORTH AMERICA, INC.	SEVERSTAL NORTH AMERICA, INC.	MI	182-05	331111	01/31/2006 ACT	INTEGRATED IRON AND STEEL PLANT	C FURNACE CASTHOUSE	PULVERIZED COAL, COKE	6700	T/D	Sulfur Dioxide (SO2)	NO FEASIBLE CONTROLS	14.65	LB/H	AVERAGING TIME PER TEST PROTOCOL	BACT-PSD	0			0		

Appendix B

Air Permit Summary for II&S Mills

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Facility	Boiler			
	Emission Unit Description	**Controls**	**NOx Limit**	**Comments**
AM Burns Harbor	1976 No. 7 Boiler 650 MMBtu/hr max HI (ea.) natural gas, coke oven gas, blast furnace gas, and fuel oil	None	0.17 lb/MMBtu & 50% Heat Input from BFG	Pursuant to 326 IAC 10-3-3: Applies to all 6 boilers, limit for each individual boiler; only applicable during ozone control periods
AM Burns Harbor	1970 No. 8 Boiler 650 MMBtu/hr max HI (ea.) natural gas, coke oven gas, blast furnace gas, No. 2 fuel oil, No. 6 fuel oil	None		
AM Burns Harbor	1970 No. 9 Boiler 650 MMBtu/hr max HI (ea.) natural gas, coke oven gas, blast furnace gas, No. 2 fuel oil, No. 6 fuel oil	None		
AM Burns Harbor	1969 No. 10 Boiler 650 MMBtu/hr max HI (ea.) natural gas, coke oven gas, blast furnace gas, No. 2 fuel oil, No. 6 fuel oil	None		
AM Burns Harbor	1968 No. 11 Boiler 650 MMBtu/hr max HI (ea.) natural gas, coke oven gas, blast furnace gas, No. 2 fuel oil, No. 6 fuel oil	None		
AM Burns Harbor	1968 No. 12 Boiler 650 MMBtu/hr max HI (ea.) natural gas, coke oven gas, blast furnace gas, No. 2 fuel oil, No. 6 fuel oil	None		
AM Indiana Harbor East	1976 No. 501 Boiler 520 MMBtu/hr max HI (ea.) Natural Gas, Blast Furnace Gas	None	0.17 lb/MMBtu & 50% Heat Input from BFG	Pursuant to 326 IAC 10-3-3(c): Applies to all 4 boilers, limit for each individual boiler; only applicable during ozone control periods
AM Indiana Harbor East	1976 No. 502 Boiler 520 MMBtu/hr max HI (ea.) Natural Gas, Blast Furnace Gas	None		
AM Indiana Harbor East	1976 No. 503 Boiler 520 MMBtu/hr max HI (ea.) Natural Gas, Blast Furnace Gas	None		
AM Indiana Harbor East	Approved in 2010 - No. 504 Boiler 561.6 MMBtu/hr max HI (ea.) Natural Gas, Blast Furnace Gas	None	240.6 tpy (12-mo. Rolling Sum)	PM10, PM2.5, SO2, NOx and CO PSD and Emission Offset Credit Limits [326 IAC 2-2] [326 IAC 2-3]: Limit is only for Boiler 504
AM Indiana Harbor West	1952 No. 5 Boiler 454 MMBtu/hr max HI (ea.) Natural Gas, blast furnace gas	None	0.17 lb/MMBtu & 50% Heat Input from BFG	Pursuant to 326 IAC 10-3-3: Applies to all 4 boilers, limit for each individual boiler; only applicable during ozone control periods
AM Indiana Harbor West	1956 No. 6 Boiler 454 MMBtu/hr max HI (ea.) Natural Gas, blast furnace gas	None		
AM Indiana Harbor West	1056 No. 7 Boiler 454 MMBtu/hr max HI (ea.) Natural Gas, blast furnace gas	None		
AM Indiana Harbor West	1967 No. 8 Boiler 1,090 MMBtu/hr max HI (ea.) Natural Gas, blast furnace gas	None		
Nucor St. James	Not Constructed - Topgas Boiler No. 1 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low NOx fuels	1. 0.2 lb/MMBtu 2. 0.092 lb/MMBtu 3. 0.137 lb/MMBtu	1. 40 CFR60.44(a)(l) (NSPS D): For all boilers individually. 2. LAC 33:III.509, BACT: For all boilers individually. Specific to BFG. This limit for Normal operation consists of a fuel mixture of Blast Furnace Top Gas and Natural gas with less than or equal to 41 % natural gas on a MMBTU / hr heat input. 3. LAC 33:III.509, BACT: For all boilers individually. Total for all fuels. This emission rate is based upon any operation with natural gas greater than 41 % heat input of the fuel up to and including 100%. Operating under this alternate operating scenario shall be minimized to the maximum extent possible.
Nucor St. James	Not Constructed - Topgas Boiler No. 2 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low NOx fuels		
Nucor St. James	Not Constructed - Topgas Boiler No. 3 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low NOx fuels		
Nucor St. James	Not Constructed - Topgas Boiler No. 4 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low NOx fuels		
Nucor St. James	Not Constructed - Topgas Boiler No. 5 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low NOx fuels		
Nucor St. James	Not Constructed - Topgas Boiler No. 6 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low NOx fuels		
Nucor St. James	Not Constructed - Topgas Boiler No. 7 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low NOx fuels		
Nucor St. James	Not Constructed - Topgas Boiler No. 8 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low NOx fuels		
USS Clairton	B001 - Boiler No. 1 760 mmbtu/hr heat input Desulfurized Coke Oven Gas and Natural Gas	None	410.40 lb/hr	
			1,740 tpy	
			0.54 lb/MMBtu	RACT Plan (shall not exceed at any time)
USS Clairton	B002 - Boiler No. 2 481 mmbtu/hr heat input Desulfurized Coke Oven Gas and Natural Gas	None	259.74 lb/hr	
			1,285 tpy	
			0.54 lb/MMBtu	RACT Plan (shall not exceed at any time)
USS Clairton	B005 - R1 Boiler 229 mmbtu/hr heat input Desulfurized Coke Oven Gas and Natural Gas	None	123.66 lb/hr	
			525 tpy	
			0.54 lb/MMBtu	RACT Plan (shall not exceed at any time)
USS Clairton	B006 - R2 Boiler 229 mmbtu/hr heat input Desulfurized Coke Oven Gas and Natural Gas	None	123.66 lb/hr	
			525 tpy	
			0.54 lb/MMBtu	RACT Plan (shall not exceed at any time)
USS Clairton	B007 - T1 Boiler 156 mmbtu/hr heat input Desulfurized Coke Oven Gas and Natural Gas	None	84.24 lb/hr	
			358 tpy	
			0.54 lb/MMBtu	RACT Plan (shall not exceed at any time)
USS Clairton	B008 - T2 Boiler 156 mmbtu/hr heat input Desulfurized Coke Oven Gas and Natural Gas	None	84.24 lb/hr	
			358 tpy	
			0.54 lb/MMBtu	RACT Plan (shall not exceed at any time)

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	Boiler			
	Emission Unit Description	**Controls**	**NOx Limit**	**Comments**
AK Dearborn	Facility does not have a boiler			
AK Middleton	P009 No. 3 Slab Reheat Furnace/Waste Heat Boiler 598 MMBtu/hr Slab Furnace 305 MMBtu/hr Waste Heat Boiler Natural gas, fuel oil, coke oven gas	None	None	
	P010 No. 2 Slab Reheat Furnace/Waste Heat Boiler 598 MMBtu/hr Slab Furnace 305 MMBtu/hr Waste Heat Boiler Natural gas, fuel oil, coke oven gas	None	None	
	P011 No. 1 Slab Reheat Furnace/Waste Heat Boiler 598 MMBtu/hr Slab Furnace 305 MMBtu/hr Waste Heat Boiler Natural gas, fuel oil, coke oven gas	None	None	
	P012 No. 4 Slab Reheat Furnace/Waste Heat Boiler 598 MMBtu/hr Slab Furnace 305 MMBtu/hr Waste Heat Boiler Natural gas, fuel oil, coke oven gas	None	None	
AM Cleveland	Facility does not have a boiler			
USS Edgar Thompson	Facility does not have a boiler			
USS East Chicago	B-1 Steam Generation Boiler 181.1 MMBtu/hr max HI (ea.) Natural gas	Low-NOx burners, Flue gas recirculation	40 tpy (12-mo. Rolling Sum)	NOx PSD and Emission Offset Minor Limit [326 IAC 2-2] [326 IAC 2-3]

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	Coke Battery			
	Emission Unit Description	**Controls**	**NOx Limit**	**Comments**
AM Burns Harbor	1983 Coke Oven Battery #1 and #2 300 tons/hr coal Coke oven gas	Baghouse Flares	650 tpy (12-mo. Rolling Sum)	Prevention of Significant Deterioration (PSD) Minor Limit [326 IAC 2-2] and Emission Offset (EO) Minor Limit [326 IAC 2-3]
AM Indiana Harbor East	Facility does not have a coke battery			
AM Indiana Harbor West	Facility does not have a coke battery			
AK Dearborn	Facility does not have a sinter plant			
AK Middleton	B198 No. 2 Coke Plant, Wilputte Underjet 76-oven Coke Battery Coke Oven Gas	Flare	None	
AM Cleveland	Facility does not have a sinter plant			
AM Monassen Coke	801 COKE BATTERIES - CHARGING	None	1 tpy (12-mo. Rolling Sum)	25 Pa. Code §127.441
AM Monassen Coke	802 COKE BATTERIES - PUSHING	PECS baghouse, Desulfurization/Recovery Plant	5 tpy (12-mo. Rolling Sum)	25 Pa. Code §127.441
AM Monassen Coke	803 COKE BATTERIES - PUSHING	Quench tower, Desulfurization/Recovery Plant	None	
AM Monassen Coke	805 COKE BATTERIES - UNDERFIRING	None	None	
AM Monassen Coke	806 COKE BATTERIES - DOOR LEAKS	None	None	
AM Monassen Coke	807 COKE BATTERIES - TOPSIDE	None	None	
AM Monassen Coke	808 COKE BATTERIES -SOAKING	None	None	
AM Monassen Coke	809 EXCESS COG FLARES (2 NON-EMERGENCY)	Flare	None	
AM Monassen Coke	810 COAL AND COKE MATERIAL HANDLING	None	None	
AM Monassen Coke	811 COAL AND COKE MATERIAL HANDLING	Flare	None	
AM Warren Coke Plant	B901/P002 No. 4 Coke Oven Battery and Tail Gas Desulfurization	None listed, likely not listed	None	
EES Coke Battery	1992, 1997, and 2014 Coke Batteries	Flares Baghouses	1411 tpy (12-mo rolling sum)	R336.2803, R336.2804
EES Coke Battery			563.5 pph (hourly average)	R336.2803, R336.2804
EES Coke Battery			0.75 lb/MMBtu (12-mo. Rolling avg)	R336.2810
EES Coke Battery			1.25 lb/MMBtu (24-hr Rolling avg)	R336.2810
EES Coke Battery			2.61 pph	For PECS baghouse stack. R336.2803, R336.2804, R336.2810

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	Coke Battery			
	Emission Unit Description	**Controls**	**NOx Limit**	**Comments**
Haverhill Coke Company	P901 AB Battery	Lime Spray Dryer Baghouse Staged Combustion	120 lb/hr	For waste gas stack. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			438 tpy (12-mo rolling sum)	For waste gas stack. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			24 lb/hr	For any HRSG stack. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			19.2 tpy	Total for all HRSG stacks on P901 and P902. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			1 lb/ton coal	For waste gas stack. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			7.68 lb/hr	From flat push car multicyclone dust collector OAC rules 3745-31-10 through 20
			7.01 tpy (12-mo rolling sum)	From flat push car multicyclone dust collector OAC rules 3745-31-10 through 20
			0.016 lb/ton coal	From flat push car multicyclone dust collector OAC rules 3745-31-10 through 20
	P902 CD Battery	Lime Spray Dryer Baghouse Staged Combustion	120 lb/hr	For waste gas stack. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			438 tpy (12-mo rolling sum)	For waste gas stack. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			24 lb/hr	For any HRSG stack. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			19.2 tpy	Total for all HRSG stacks on P901 and P902. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			1 lb/ton coal	For waste gas stack. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			7.68 lb/hr	From flat push car multicyclone dust collector OAC rules 3745-31-10 through 20
			7.01 tpy (12-mo rolling sum)	From flat push car multicyclone dust collector OAC rules 3745-31-10 through 20
			0.016 lb/ton coal	From flat push car multicyclone dust collector OAC rules 3745-31-10 through 20
Indiana Harbor Coke	Coke oven charging, pushing, and oven units 5,589 ton/day coke	Baghouse Lime Spray Dryer	40 tpy	Prevention of Significant Deterioration (PSD) Minor Limits [326 IAC 2-2]
Jewel Coke Company	143 Thompson Sole Flue Non-Recovery Coke Ovens	Afterburner Baghouses	29.07 lb/hr	9 VAC 5-80-110, 9 VAC 5-50-180, 9 VAC 5-50-260 and Condition 8 of NSR permit dated 6/12/02
	Heyl & Patterson Model 135 Thermal Dryer	Venturi Scubber	None	
Nucor St. James	COK-102 Coke Battery 1 Coke Pushing 1,102,311 tons/yr coal	None	0.02 lb/ton coke	LAC 33:III.509, BACT
	COK-202 Coke Battery 2 Coke Pushing 1,102,311 tons/yr coal	None	0.02 lb/ton coke	LAC 33:III.509, BACT
	COK-111 Coke Battery 1 FGD Stack 1,725,720 tons/yr coal	Staged Combustion	0.71 lb/ton coke	LAC 33:III.509, BACT
	COK-211 Coke Battery 2 FGD Stack 1,725,720 tons/yr coal	Staged Combustion	0.71 lb/ton coke	LAC 33:III.509, BACT
	PCS 0002 Coke Battery Area	None	None	
SunCoke Energy Midtown	P901 Coke Battery	None listed, likely not listed	None	

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	Coke Battery			
	Emission Unit Description	**Controls**	**NOx Limit**	**Comments**
USS Clairton	P001 Coke Battery No. 1 517,935 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	None	
	P002 Coke Battery No. 2 517,935 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	None	
	P003 Coke Battery No. 3 517,935 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	None	
	P007 Coke Battery No. 13 545,675 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	None	
	P008 Coke Battery No. 14 545,675 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	None	
	P009 Coke Battery No. 15 545,675 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	None	
	P010 Coke Battery No. 19 1,002,290 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	None	
	P011 Coke Battery No. 20 1,002,290 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	None	
	P012 Coke Battery B 1,491,025 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	None	
	P001 Coke Battery No. 1 517,935 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	None	
	P019 Desulfurization Plant 6,394,800 tons/yr coke Coke Oven Tail Gas	Afterburner SRU-SCOT Plant and Incinerator	500 ppmd 0.4 gr H2S/dscf coke oven gas	§2104.03.c §2105.21.h
USS Gary Works	Facility does not have a coke battery			
USS East Chicago	Facility does not have a sinter plan			
USS Edgar Thompson	Facility does not have a sinter plant			

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	Blast Furnace Stoves, Casthouses, and Slag Pits			
	Emission Unit Description	**Controls**	**NOx Limit**	**Comments**
AM Burns Harbor	1971 C Blast Furnace Consisting of C Blast Furnace Stoves 623 tons/hr iron (total with D Blast Furnace) 660 MMBtu/hr max HI total	integral gas cleaning system consisting of various components including a dust catcher, separator, and 2 scrubbers (primary and secondary), which provides clean fuel to the plant fuel distribution system with excess gas flared	None	Listed controls are for CO only.
		Stoves, exhausting to combustion stack (EP520-3547) with an estimated heat input rate of 660 MMBtu/hr		Primarily combust BFG which is a low NOx fuel
		East and West casthouses with iron and slag runner fugitive emissions reporting to roof monitors EP520-3543 and 3545 respectively and tap hole and tilting runner emissions controlled by MACT baghouse installed in 2007		Listed controls are for PM only.
	1968 D Blast Furnace Consisting of D Blast Furnace Stoves 623 tons/hr iron (total with C Blast Furnace) 660 MMBtu/hr max HI total	integral gas cleaning system consisting of various components including a dust catcher, separator, and 2 scrubbers (primary and secondary), which provides clean fuel to the plant fuel distribution system with excess gas flared	None	Listed controls are for CO only.
		Stoves, exhausting to combustion stack (EP520-3560) with an estimated heat input rate of 660 MMBtu/hr		Primarily combust BFG which is a low NOx fuel
		East and West casthouses with iron and slag runner fugitive emissions reporting to roof monitors EP520-3556 and 3558 respectively and respectively and tap hole and tilting runner emissions controlled by MACT baghouse installed in 2007		Listed controls are for PM only.
AM Indiana Harbor East	1980 No. 7 Blast Furnace Comprised of four No. 7 Blast Furnace Stoves 4.417 Mmtons/yr metal production 953 MMBtu/hr max HI total Pulverized coal (132 tons/hr) / Natural Gas / Blast Furnace Gas	Integral gas cleaning system with excess gas exhausting through Three (3) flares, each with a 1.15 MMBtu per hour igniter capacity of flaring one-third of the maximum generated blast furnace gas through stack 195	None	Listed controls are for CO only.
		Four Stoves have no controls for NOx		Primarily combust BFG which is a low NOx fuel
		Casthouse emissions controlled by two baghouses rated at 500,000 acfm (stack 166) and 300,000 acfm (stack 167) respectively.		Listed controls are for PM only.
		PCI system has two pulverizers each with cyclone and baghouse (stack 187).		Listed controls are for PM only.
AM Indiana Harbor West	1953 No. 3 Blast Furnace Including three No. 3 Blast Furnace Stoves 4.5552 Mmtons/yr input 441 MMBtu/hr max HI total	integral gas cleaning system consisting of a dust catcher, separator, two scrubbers (primary and secondary) and one cooling tower, with excess gas exhausting through a flare at stack (S1E)	None	Listed controls are for CO only.
		Three Stoves have no controls for NOx		Primarily combust BFG which is a low NOx fuel
		Passive Emission Control (PEC) to suppress fumes in the casthouse, consisting of slag and iron runner covers along with natural gas flame suppression exhausting to the No. 3 Blast		Listed controls are for PM only.
	1967 No. 4 Blast Furnace Including three No. 4 Blast Furnace Stoves 5.490836 Mmtons/yr input 486 MMBtu/hr max HI total	integral gas cleaning system consisting of a dust catcher, separator, two scrubbers (primary and secondary) and one cooling tower with excess gas exhausting through a flare at stack (S1D)	None	Listed controls are for CO only.
		Three Stoves have no controls for NOx		Primarily combust BFG which is a low NOx fuel
		Passive Emission Control (PEC) to suppress fumes in the casthouse, consisting of slag and iron runner covers along with natural gas flame suppression exhausting to the No. 4 Blast Furnace Casthouse Roof Monitor (V1B). No. 4 Blast Furnace Casthouse Baghouse used to control emissions from the casthouse with an airflow rate of 147,000 acfm exhausting at stack (S1B) when operating one (1) fan. No. 4 Blast Furnace Casthouse Baghouse has an air flow rate of 240,000 acfm when operating two (2) fans.		Listed controls are for PM only.
	2 Ladle Burners	None	None	
	Railcar Thaw Shed Heater 50.4 MMBtu/hr max HI total	None	None	
USS Gary Works	IDBF0369 No. 14 Blast Furnace Comprised of three No. 14 Blast Furnace Stoves (IDST0359) 450 tons metal production/hr 700 MMBtu/hr max HI total Natural gas / Pulverized coal (80 tons/hr) / Oil (150	Stockhouse Baghouse	None	
Nucor St. James	Not Constructed Blast Furnace 1 1,088 MMBtu/hr Natural gas, Blast furnace gas	Low NOx fuels	0.06 lb/MMBtu	LAC 33:III.509, BACT
	Not Constructed Casthouse No. 1	None	None	
	Not Constructed Blast Furnace 2 1,088 MMBtu/hr Natural gas, Blast furnace gas	Low NOx fuels	0.06 lb/MMBtu	LAC 33:III.509, BACT
	Not Constructed Casthouse No. 2	None	None	
USS Clairton	Facility does not have a blast furnace			
AK Dearborn	1/1/1922 EUBFURNACE (part of FGB&CFURNACES), group of 4 stoves with a common stack, cast house emission control system (collection hoods, baghouse, stack), a blast furnace gas scrubber and dust collector, semi-clean bleeder, and dirty gas bleeder. 3,321,500 tons iron/yr (material limit on FGB&CFURNACES) Natural gas, Blast furnace gas	Stoves: Low-Nox Technology Casthouse: Baghouse Venturi scrubber and mechanical collector for blast furnace pre-cleaning	25.74 tons/yr (12mo rolling)	Limit on: FGB&CFURNACES baghouse stacks R336.2801 - R336.2804 -- PSD
	1/1/1948, 10/1/2007 EUCFURNACE (part of FGB&CFURNACES), group of 4 stoves with a common		439.2 tons/yr (12mo rolling)	Limit on: FGB&CFURNACES stove stacks R336.2801 - R336.2804 -- PSD
AK Middleton	P925 No. 3 Blast Furnace 740 tons metal production/hr	For PM control: equipped with a casthouse baghouse, a settling chamber/dustcatcher (cyclone), a wet venturi scrubber system (Bischoff), stoves, and a blast furnace gas flare	None	

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Regional Haze Four-Factor Analyses for NO_X and SO_2 Emissions Control

Appendix B: Air Permit Summary for II&S Mills

	Blast Furnace Stoves, Casthouses, and Slag Pits			
	Emission Unit Description	**Controls**	**NOx Limit**	**Comments**
AM Cleveland	P903 Blast Furnace C5	equipped with a venturi scrubber for cleaning reusable blast furnace gas, natural gas suppression, oxygen enrichment, dirty and clean gas bleeders, and flue dust handling with passive emission control (PEC) system, and flare	0.06 lbs/MMBtu	for furnace stoves
AM Cleveland	P904 Blast Furnace C6	equipped with a venturi scrubber for cleaning reusable blast furnace gas, natural gas suppression, oxygen enrichment, dirty and clean gas bleeders, and flue dust handling with passive emission control (PEC) system and a flare	0.06 lbs/MMBtu	for furnace stoves
USS Edgar Thompson	P001a Blast Furnace No. 1 Casthouse 1,752,000 tpy (production capacity) Coke, Iron-bearing materials, fluxes	Stack S002, Casthouse Baghouse (shared between P001a and P002a)	None	
USS Edgar Thompson	P001b Blast Furnace No. 1 Stoves 495 MMBtu/hr BFG, COG, Natural Gas	Stack S001, Dust Catch/Venturi scrubber for BFG cleaning	None	
USS Edgar Thompson	P001c BFG Flare 3 MMcfh BFG	Stack S003	None	
USS Edgar Thompson	P002a Blast Furnace No. 3 Casthouse 1,752,000 tpy (production capacity) Coke, Iron-bearing materials, fluxes	Stack S002, Casthouse Baghouse (shared between P001a and P002a)	None	
USS Edgar Thompson	P002b Base Furnace No. 3 Stoves 495 MMBtu/hr BFG, COG, Natural Gas	Stack S004, Dust Catch/Venturi scrubber for BFG cleaning	None	
USS East Chicago	Facility does not have a blast furnace			

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	Boilers			
	Emission Unit Description	**Controls**	**SO2 Limit**	**Comments**
AM Burns Harbor	1976 No. 7 Boiler 650 MMBtu/hr max HI (ea.) natural gas, coke oven gas, blast furnace gas, and fuel oil	None	None	
AM Burns Harbor	1970 No. 8 Boiler 650 MMBtu/hr max HI (ea.) natural gas, coke oven gas, blast furnace gas, No. 2 fuel oil, No. 6 fuel oil	None		
AM Burns Harbor	1970 No. 9 Boiler 650 MMBtu/hr max HI (ea.) natural gas, coke oven gas, blast furnace gas, No. 2 fuel oil, No. 6 fuel oil	None		
AM Burns Harbor	1969 No. 10 Boiler 650 MMBtu/hr max HI (ea.) natural gas, coke oven gas, blast furnace gas, No. 2 fuel oil, No. 6 fuel oil	None		
AM Burns Harbor	1968 No. 11 Boiler 650 MMBtu/hr max HI (ea.) natural gas, coke oven gas, blast furnace gas, No. 2 fuel oil, No. 6 fuel oil	None		
AM Burns Harbor	1968 No. 12 Boiler 650 MMBtu/hr max HI (ea.) natural gas, coke oven gas, blast furnace gas, No. 2 fuel oil, No. 6 fuel oil	None		
AM Indiana Harbor East	1976 No. 501 Boiler 520 MMBtu/hr max HI (ea.) Natural Gas, Blast Furnace Gas	None	0.198 lb/MMBtu 265.2 lb/hr	Pursuant to 326 IAC 7-4.1-11(a): Limits are for all 4 boilers in total
AM Indiana Harbor East	1976 No. 502 Boiler 520 MMBtu/hr max HI (ea.) Natural Gas, Blast Furnace Gas	None		
AM Indiana Harbor East	1976 No. 503 Boiler 520 MMBtu/hr max HI (ea.) Natural Gas, Blast Furnace Gas	None		
AM Indiana Harbor East	Approved in 2010 - No. 504 Boiler 561.6 MMBtu/hr max HI (ea.)	None		
AM Indiana Harbor West	1952 No. 5 Boiler 454 MMBtu/hr max HI (ea.) Natural Gas, blast furnace gas	None	1. 0.594 lb/MMBtu 2. 1,456.5 lbs/hr 3. 5,871.61 tpy	1. Pursuant to 326 IAC 7-4.1-10(a)(1): Limit applies to all 4 boilers, for each individual stack 2. Pursuant to 326 IAC 7-4.1-10(a)(1): Limit applies to all 4 boilers in total 3. Pursuant to 326 IAC 7-4.1-10(a)(1): Limit applies to all 4 boilers in total, also with Ironside Energy, LLC Utility Boiler No. 9
AM Indiana Harbor West	1956 No. 6 Boiler 454 MMBtu/hr max HI (ea.) Natural Gas, blast furnace gas	None		
AM Indiana Harbor West	1056 No. 7 Boiler 454 MMBtu/hr max HI (ea.) Natural Gas, blast furnace gas	None		
AM Indiana Harbor West	1967 No. 8 Boiler 1,090 MMBtu/hr max HI (ea.) Natural Gas, blast furnace gas	None		
Nucor St. James	Not Constructed - Topgas Boiler No. 1 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low sulfur fuels	1. 1.2 lb/MMBtu 2. 0.008 lb/MMBtu 3. 0.002 gr/dscf 4. 0.022 lb/MMBtu	1. 40 CFR60.43(a)(2) (NSPS D): For all boilers individually 2. LAC 33:III.509, BACT: For all boilers individually. Specific to BFG. This limit for Normal operation consists of a fuel mixture of Blast Furnace Top Gas and Natural gas with less than or equal to 41 % natural gas on a MMBTU / hr heat input. 3. LAC 33:III.509, BACT: Sulfur content in natural gas 4. LAC 33:III.509, BACT: For all boilers individually. Total for all fuels. This emission rate is based upon any operation with natural gas greater than 41 % heat input of the fuel up to and including 100%. Operating under this alternate operating scenario shall be minimized to the maximum extent possible.
Nucor St. James	Not Constructed - Topgas Boiler No. 2 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low sulfur fuels		
Nucor St. James	Not Constructed - Topgas Boiler No. 3 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low sulfur fuels		
Nucor St. James	Not Constructed - Topgas Boiler No. 4 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low sulfur fuels		
Nucor St. James	Not Constructed - Topgas Boiler No. 5 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low sulfur fuels		
Nucor St. James	Not Constructed - Topgas Boiler No. 6 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low sulfur fuels		
Nucor St. James	Not Constructed - Topgas Boiler No. 7 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low sulfur fuels		
Nucor St. James	Not Constructed - Topgas Boiler No. 8 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low sulfur fuels		
USS Clairton	B001 - Boiler No. 1 760 mmbtu/hr heat input Desulfurized Coke Oven Gas and Natural Gas	None	163.50 lb/hr 716.11 tpy	County-only enforceable, per permit County-only enforceable, per permit
USS Clairton	B002 - Boiler No. 2 481 mmbtu/hr heat input Desulfurized Coke Oven Gas and Natural Gas	None	103.48 lb/hr 453.22 tpy	County-only enforceable, per permit County-only enforceable, per permit
USS Clairton	B005 - R1 Boiler 229 mmbtu/hr heat input Desulfurized Coke Oven Gas and Natural Gas	None	49.26 lb/hr 215.78 tpy	County-only enforceable, per permit County-only enforceable, per permit
USS Clairton	B006 - R2 Boiler 229 mmbtu/hr heat input Desulfurized Coke Oven Gas and Natural Gas	None	49.26 lb/hr 215.78 tpy	County-only enforceable, per permit County-only enforceable, per permit
USS Clairton	B007 - T1 Boiler 156 mmbtu/hr heat input Desulfurized Coke Oven Gas and Natural Gas	None	33.56 lb/hr 146.99 tpy	
USS Clairton	B008 - T2 Boiler 156 mmbtu/hr heat input Desulfurized Coke Oven Gas and Natural Gas	None	33.56 lb/hr 146.99 tpy	

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Appendix B: Air Permit Summary for II&S Mills

	Boilers			
	Emission Unit Description	Controls	SO2 Limit	Comments
AK Dearborn	Facility does not have a boiler			
AK Middleton	P009 No. 3 Slab Reheat Furnace/Waste Heat Boiler 598 MMBtu/hr Slab Furnace 305 MMBtu/hr Waste Heat Boiler Natural gas, fuel oil, coke oven gas	None	1.10 lbs/MMBtu	OAC rule citation(s)
	P010 No. 2 Slab Reheat Furnace/Waste Heat Boiler 598 MMBtu/hr Slab Furnace 305 MMBtu/hr Waste Heat Boiler Natural gas, fuel oil, coke oven gas	None	1.10 lbs/MMBtu	OAC rule citation(s)
	P011 No. 1 Slab Reheat Furnace/Waste Heat Boiler 598 MMBtu/hr Slab Furnace 305 MMBtu/hr Waste Heat Boiler Natural gas, fuel oil, coke oven gas	None	1.10 lbs/MMBtu	OAC rule citation(s)
	P012 No. 4 Slab Reheat Furnace/Waste Heat Boiler 598 MMBtu/hr Slab Furnace 305 MMBtu/hr Waste Heat Boiler Natural gas, fuel oil, coke oven gas	None	1.10 lbs/MMBtu	OAC rule citation(s)
AM Cleveland	Facility does not have a boiler			
USS Edgar Thompson	Facility does not have a boiler			
USS East Chicago	B-1 Steam Generation Boiler 181.1 MMBtu/hr max HI (ea.) Natural gas	Flue gas recirculation	None	

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	Coke Battery			
	Emission Unit Description	**Controls**	**SO2 Limit**	**Comments**
AM Burns Harbor	1983 Coke Oven Battery #1 and #2 300 tons/hr coal Coke oven gas	Baghouse Flares	None	
AM Indiana	Facility does not have a coke battery			
AM Indiana Harbor West	Facility does not have a coke battery			
AK Dearborn	Facility does not have a sinter plant			
AK Middleton	B198 No. 2 Coke Plant, Wilputte Underjet 76-oven Coke Battery Coke Oven Gas	Flare	2.8 gr H2S/dscf (30-day Rolling Average)	Limit on coke oven gas. OAC rule 3745-18-15(C)(3)(a)
AM Cleveland	Facility does not have a sinter plant			
AM Monassen Coke	801 COKE BATTERIES - CHARGING	None	None	
	802 COKE BATTERIES - PUSHING	PECS baghouse, Desulfurization/Recovery Plant	None	
	803 COKE BATTERIES - PUSHING	Quench tower, Desulfurization/Recovery Plant	None	
	805 COKE BATTERIES - UNDERFIRING	None	None	
	806 COKE BATTERIES - DOOR LEAKS	None	None	
	807 COKE BATTERIES - TOPSIDE	None	None	
	808 COKE BATTERIES -SOAKING	None	None	
	809 EXCESS COG FLARES (2 NON-EMERGENCY)	Flare	None	
	810 COAL AND COKE MATERIAL HANDLING	None	None	
	811 COAL AND COKE MATERIAL HANDLING	Flare	None	
AM Warren Coke Plant	B901/P002 No. 4 Coke Oven Battery and Tail Gas Desulfurization	None listed, likely not listed	0.35 gr H2S/dscf	Limit for coke oven gas combusted. OAC rule 3745-31-05 (PTI No. 02-171)
EES Coke Battery	1992, 1997, and 2014 Coke Batteries	Flares Baghouses	2071 tpy (12-mo rolling sum) 544.6 pph (3-hr block avg) 0.702 lb/Mscf coke oven gas	R336.1205(1)(a) and (1)(b), 40 CFR 52.21(c) and (d) 40 CFR 52.21(c) and (d) R336.1205(1)(a) and (1)(b), Section 110 of CAA

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	Coke Battery			
	Emission Unit Description	**Controls**	**SO2 Limit**	**Comments**
Haverhill Coke Company	P901 AB Battery	Lime Spray Dryer Baghouse Staged Combustion	192 lb/hr (3-hr block average)	40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			700.8 tpy (12-mo rolling sum)	40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			420 lb/hr (3-hr block average)	For any HRSG stack. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			323 lb/hr (48-hr rolling average)	For any HRSG stack during bypass venting longer than 48 hours. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			384 tpy	Total for all HRSG stacks on P901 and P902. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			520.8 tons/24-mo. (Rolling sum)	Total for all HRSG stacks on P901 and P902. Not enforcable until 2021. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			1.6 lb/ton coal	For waste gas stack. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			0.14 lb/hr	For charging baghouse. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			0.13 tpy (12-mo rolling sum)	For charging baghouse. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			0.0003 lb/ton coal	For charging baghouse. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			24 lb/hr	From flat push car multicyclone dust collector OAC rules 3745-31-10 through 20
			21.9 tpy (12-mo rolling sum)	From flat push car multicyclone dust collector OAC rules 3745-31-10 through 20
			0.05 lb/ton coal	From flat push car multicyclone dust collector OAC rules 3745-31-10 through 20
	P902 CD Battery	Lime Spray Dryer Baghouse Staged Combustion	192 lb/hr (3-hr block average)	40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			700.8 tpy (12-mo rolling sum)	40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			420 lb/hr (3-hr block average)	For any HRSG stack. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			323 lb/hr (48-hr rolling average)	For any HRSG stack during bypass venting longer than 48 hours. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			384 tpy	Total for all HRSG stacks on P901 and P902. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			520.8 tons/24-mo. (Rolling sum)	Total for all HRSG stacks on P901 and P902. Not enforcable until 2021. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			1.6 lb/ton coal	For waste gas stack. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			0.14 lb/hr	For charging baghouse. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			0.13 tpy (12-mo rolling sum)	For charging baghouse. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			0.0003 lb/ton coal	For charging baghouse. 40 CFR Part 52.21 and OAC rules 3745-31-10 through 20
			24 lb/hr	From flat push car multicyclone dust collector OAC rules 3745-31-10 through 20
			21.9 tpy (12-mo rolling sum)	From flat push car multicyclone dust collector OAC rules 3745-31-10 through 20
			0.05 lb/ton coal	From flat push car multicyclone dust collector OAC rules 3745-31-10 through 20
Indiana Harbor Coke	Coke oven charging, pushing, and oven units 5,589 ton/day coke	Baghouse Lime Spray Dryer	0.0068 lb/ton coal	For charging. 326 IAC 7-4.1-8
			1.57 lb/hr	For charging. 326 IAC 7-4.1-8
			0.0084 lb/ton coal	For pushing. 326 IAC 7-4.1-8
			1.96 lb/hr	For pushing. 326 IAC 7-4.1-8
			0.0053 lb/ton coal	For quenching. 326 IAC 7-4.1-8
			1.232 lb/hr	For quenching. 326 IAC 7-4.1-8
			1656 lb/hr	For waste gas stack. 326 IAC 7-4.1-8
Jewel Coke Company	143 Thompson Sole Flue Non-Recovery Coke Ovens	Afterburner Baghouses	310 lb/hr	9 VAC 5-80-110, 9 VAC 5-50-180, 9 VAC 5-50-260 and Condition 8 of NSR permit dated 6/12/02
	Heyl & Patterson Model 135 Thermal Dryer	Venturi Scrubber	1.4 lb/hr	VAC 5-50-260, 9 VAC 5-80-110 and Condition 10 of NSR permit dated 6/12/02
			3.9 tpy (12-mo rolling sum)	VAC 5-50-260, 9 VAC 5-80-110 and Condition 10 of NSR permit dated 6/12/02
Nucor St. James	COK-102 Coke Battery 1 Coke Pushing 1,102,311 tons/yr coal	None	0.10 lb/ton coke	LAC 33:III.509, BACT
	COK-202 Coke Battery 2 Coke Pushing 1,102,311 tons/yr coal	None	0.10 lb/ton coke	LAC 33:III.509, BACT
	COK-111 Coke Battery 1 FGD Stack 1,725,720 tons/yr coal	None listed, likely not listed	2000 ppmv	LAC 33:III.1503.C
	COK-211 Coke Battery 2 FGD Stack 1,725,720 tons/yr coal	None listed, likely not listed	2000 ppmv	LAC 33:III.1503.C
	PCS 0002 Coke Battery Area	None	1.25% Sulfur in Charge 37% Redyction by Weight of Retained Sulfur	LAC 33:III.509, BACT

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	Coke Battery			
	Emission Unit Description	**Controls**	**SO2 Limit**	**Comments**
SunCoke Energy Midtown	P901 Coke Battery	None listed, likely not listed	None	
USS Clairton	P001 Coke Battery No. 1 517,935 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	139.46 tpy 31.8 lb/hr 10.41 lb/hr (30-day Rolling Average) 13.27 lb/hr (24-hr Average) 0.4 gr H2S/dscf	Limit for a consecutive 12-mo period. Same limit used on lb/hr basis (8760 hr/yr). §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2102.04.b.6, §2105.21.h §2102.04.b.6, §2105.21.h §2105.21.h; §2105.21.h.4
USS Clairton	P002 Coke Battery No. 2 517,935 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	139.46 tpy 31.8 lb/hr 9.15 lb/hr (30-day Rolling Average) 11.66 lb/hr (24-hr Average) 0.4 gr H2S/dscf	Limit for a consecutive 12-mo period. Same limit used on lb/hr basis (8760 hr/yr). §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2102.04.b.6, §2105.21.h §2102.04.b.6, §2105.21.h §2105.21.h; §2105.21.h.4
USS Clairton	P003 Coke Battery No. 3 517,935 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	139.46 tpy 31.8 lb/hr 10.57 lb/hr (30-day Rolling Average) 13.47 lb/hr (24-hr Average) 0.4 gr H2S/dscf	Limit for a consecutive 12-mo period. Same limit used on lb/hr basis (8760 hr/yr). §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2102.04.b.6, §2105.21.h §2102.04.b.6, §2105.21.h §2105.21.h; §2105.21.h.4
USS Clairton	P007 Coke Battery No. 13 545,675 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	146.5 tpy 33.5 lb/hr 13.93 lb/hr (30-day Rolling Average) 15.7 lb/hr (24-hr Average) 0.4 gr H2S/dscf	Limit for a consecutive 12-mo period. Same limit used on lb/hr basis (8760 hr/yr). §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2102.04.b.6, §2105.21.h §2102.04.b.6, §2105.21.h §2105.21.h; §2105.21.h.4
USS Clairton	P008 Coke Battery No. 14 545,675 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	146.5 tpy 33.5 lb/hr 14.03 lb/hr (30-day Rolling Average) 15.8 lb/hr (24-hr Average) 0.4 gr H2S/dscf	Limit for a consecutive 12-mo period. Same limit used on lb/hr basis (8760 hr/yr). §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2102.04.b.6, §2105.21.h §2102.04.b.6, §2105.21.h §2105.21.h; §2105.21.h.4
USS Clairton	P009 Coke Battery No. 15 545,675 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	146.5 tpy 33.5 lb/hr 18.67 lb/hr (30-day Rolling Average) 21.04 lb/hr (24-hr Average) 0.4 gr H2S/dscf	Limit for a consecutive 12-mo period. Same limit used on lb/hr basis (8760 hr/yr). §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2102.04.b.6, §2105.21.h §2102.04.b.6, §2105.21.h §2105.21.h; §2105.21.h.4
USS Clairton	P010 Coke Battery No. 19 1,002,290 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	269.48 tpy 61.53lb/hr 29.37 lb/hr (30-day Rolling Average) 33.09 lb/hr (24-hr Average) 0.4 gr H2S/dscf	Limit for a consecutive 12-mo period. Same limit used on lb/hr basis (8760 hr/yr). §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2102.04.b.6, §2105.21.h §2102.04.b.6, §2105.21.h §2105.21.h; §2105.21.h.4
USS Clairton	P011 Coke Battery No. 20 1,002,290 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	269.48 tpy 61.53lb/hr 27 lb/hr (30-day Rolling Average) 30.42 lb/hr (24-hr Average) 0.4 gr H2S/dscf	Limit for a consecutive 12-mo period. Same limit used on lb/hr basis (8760 hr/yr). §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2102.04.b.6, §2105.21.h §2102.04.b.6, §2105.21.h §2105.21.h; §2105.21.h.4
USS Clairton	P012 Coke Battery B 1,491,025 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	400.95 tpy 91.5 lb/hr 21.38 lb/hr (30-day Rolling Average) 27.26 lb/hr (24-hr Average) 0.4 gr H2S/dscf	Limit for a consecutive 12-mo period. Same limit used on lb/hr basis (8760 hr/yr). §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2105.21.f.2; §2105.21.h.4; §2103.12.e; §2101.11.b & c. §2102.04.b.6, §2105.21.h §2102.04.b.6, §2105.21.h §2105.21.h; §2105.21.h.4
USS Clairton	P046 Coke Battery C 1,379,059 tons coal/yr Natural gas, coke oven gas	Moveable hood with Baghouse Flare System	27 lb/hr (30-day Rolling Average) 30.42 lb/hr (24-hr Average)	§2102.04.b.6, §2105.21.h §2105.21.h; §2105.21.h.4
USS Clairton	P019 Desulfurization Plant 6,394,800 tons/yr coke Coke Oven Tail Gas	Afterburner SRU-SCOT Plant and Incinerator	None	

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Appendix B: Air Permit Summary for II&S Mills

	Coke Battery			
	Emission Unit Description	Controls	SO2 Limit	Comments
USS Gary Works	Facility does not have a coke battery			
USS East Chicago	Facility does not have a sinter plan			
USS Edgar Thompson	Facility does not have a sinter plant			

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Regional Haze Four-Factor Analyses for NO_X and SO_2 Emissions Control

Appendix B: Air Permit Summary for II&S Mills

Blast Furnace Stoves, Casthouses, and Slag Pits				
	Emission Unit Description	Controls	SO2 Limit	Comments
AM Burns Harbor	1971 C Blast Furnace Consisting of C Blast Furnace Stoves 623 tons/hr iron (total with D Blast Furnace) 660 MMBtu/hr max HI total	Integral gas cleaning system consisting of various components including a dust catcher, separator, and 2 scrubbers (primary and secondary), which provides clean fuel to the plant fuel distribution system with excess gas flared	None	Listed controls are for CO only.
		Stoves, exhausting to combustion stack (EP520-3547) with an estimated heat input rate of 660 MMBtu/hr		Primarily combust BFG which is a low NOx fuel
		East and West casthouses with iron and slag runner fugitive emissions reporting to roof monitors EP520-3543 and 3545 respectively and tap hole and tilting runner emissions controlled by MACT baghouse installed in 2007		Listed controls are for PM only.
	1968 D Blast Furnace Consisting of D Blast Furnace Stoves 623 tons/hr iron (total with C Blast Furnace) 660 MMBtu/hr max HI total	Integral gas cleaning system consisting of various components including a dust catcher, separator, and 2 scrubbers (primary and secondary), which provides clean fuel to the plant fuel distribution system with excess gas flared	None	Listed controls are for CO only.
		Stoves, exhausting to combustion stack (EP520-3560) with an estimated heat input rate of 660 MMBtu/hr		Primarily combust BFG which is a low NOx fuel
		East and West casthouses with iron and slag runner fugitive emissions reporting to roof monitors EP520-3556 and 3558 respectively and respectively and tap hole and tilting runner emissions controlled by MACT baghouse installed in 2007		Listed controls are for PM only.
AM Indiana Harbor East	1980 No. 7 Blast Furnace Comprised of four No. 7 Blast Furnace Stoves 4.417 Mmtons/yr metal production 953 MMBtu/hr max HI total Pulverized coal (132 tons/hr) / Natural Gas / Blast Furnace Gas	Integral gas cleaning system with excess gas exhausting through Three (3) flares, each with a 1.15 MMBtu per hour igniter capacity of flaring one-third of the maximum generated blast furnace gas through stack 195	None	Listed controls are for CO only.
		Four Stoves have no controls for SO2	0.195 lb/MMBtu 162 lb/hr	Pursuant to 326 IAC 7-4.1-11(a) Limit on: Blast Furnace No. 7 Stove Stack
		Casthouse emissions controlled by two baghouses rated at 500,000 acfm (stack 166) and 300,000 acfm (stack 167) respectively.	0.22 lb/ton 50.4 lb/hr per BH	Pursuant to 326 IAC 7-4.1-11(a) Limit on: Blast Furnace No. 7 Casthouse Listed controls are for PM only.
		PCI system has two pulverizers each with cyclone and baghouse (stack 187).	None	Listed controls are for PM only.
AM Indiana Harbor West	1953 No. 3 Blast Furnace Comprised of three No. 3 Blast Furnace Stoves 4.5552 Mmtons/yr input 441 MMBtu/hr max HI total	Integral gas cleaning system consisting of a dust catcher, separator, two scrubbers (primary and secondary) and one cooling tower, with excess gas exhausting through a flare at stack (S1E)	None	Listed controls are for CO only.
		Three Stoves have no controls for SO2	0.29 lb/MMBtu 127.89 lb/hr	Pursuant to 326 IAC 7-4.1-10(a)(4)(A) Limit on: Blast Furnace No. 3 Stove Stack
		Passive Emission Control (PEC) to suppress fumes in the casthouse, consisting of slag and iron runner covers along with natural gas flame suppression exhausting to the No. 3 Blast Furnace Casthouse Roof Monitor (V1A).	None	Listed controls are for PM only.
	1967 No. 4 Blast Furnace Comprised of three No. 4 Blast Furnace Stoves 5.490836 Mmtons/yr input 486 MMBtu/hr max HI total	Integral gas cleaning system consisting of a dust catcher, separator, two scrubbers (primary and secondary) and one cooling tower with excess gas exhausting through a flare at stack (S1D)	None	Listed controls are for CO only.
		Three Stoves have no controls for SO2	0.29 lb/MMBtu 140.94 lb/hr	Pursuant to 326 IAC 7-4.1-10(a)(4)(B) Limit on: Blast Furnace No. 4 Stove Stack
		Passive Emission Control (PEC) to suppress fumes in the casthouse, consisting of slag and iron runner covers along with natural gas flame suppression exhausting to the No. 4 Blast Furnace Casthouse Roof Monitor (V1B). No. 4 Blast Furnace Casthouse Baghouse used to control emissions from the casthouse with an airflow rate of 147,000 acfm exhausting at stack (S1B) when operating one (1) fan. No. 4 Blast Furnace Casthouse Baghouse has an air flow rate of 240,000 acfm when operating two (2) fans.	0.18 lb/ton 69.9 lb/hr	Pursuant to 326 IAC 7-4.1-10(a)(6) Limit on : Blast Furnace No. 4 Casting Listed controls are for PM only.
	2 Ladle Burners 36 MMBtu/hr max HI total	None	None	
	Railcar Thaw Shed Heater 50.4 MMBtu/hr max HI total	None	None	
USS Gary Works	IDBF0369 No. 14 Blast Furnace Comprised of three No. 14 Blast Furnace Stoves (IDST0359) 450 tons metal production/hr 700 MMBtu/hr max HI total Natural gas / Pulverized coal (80 tons/hr) / Oil (150 gal/min) and/or coal tar (150 gal/min)	Stockhouse Baghouse	0.134 lb/MMBtu	Limit on: Blast Furnace No. 14 Stove Stack
			93.5 lb/hr total	Limit on: Blast Furnace No. 14 Stove Stack
			115 lb/hr	Limit on: Blast Furnace No. 14 Casthouse Baghouse Stack
Nucor St. James	Not Constructed Blast Furnace 1 1,088 MMBtu/hr Natural gas, Blast furnace gas	Low sulfur fuels	0.002 gr/dscf Natural Gas (SO2 as H2S) 0.00874 gr/dscf BFG	LAC 33:III.509, BACT: Sulfur content in natural gas
	Not Constructed Casthouse No. 1	None	0.040 lb/ton hot metal	LAC 33:III.509, BACT
	Not Constructed Blast Furnace 2 1,088 MMBtu/hr Natural gas, Blast furnace gas	Low sulfur fuels	0.002 gr/dscf Natural Gas (SO2 as H2S) 0.00874 gr/dscf BFG	LAC 33:III.509, BACT: Sulfur content in natural gas
	Not Constructed Casthouse No. 2	None	0.040 lb/ton hot metal	LAC 33:III.509, BACT
USS Clairton	Facility does not have a blast furnace			

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emissions Control

Appendix B: Air Permit Summary for II&S Mills

	Blast Furnace Stoves, Casthouses, and Slag Pits			
	Emission Unit Description	Controls	SO2 Limit	Comments
AK Dearborn	1/1/1922 EUBFURNACE (part of FGB&CFURNACES), group of 4 stoves with a common stack, cast house emission control system (collection hoods, baghouse, stack), a blast furnace gas scrubber and dust collector, semi-clean bleeder, and dirty gas bleeder. 3,321,500 tons iron/yr (material limit on FGB&CFURNACES) Natural gas, Blast furnace gas	Stoves: No SO2 controls Casthouse: Baghouse Venturi scrubber and mechanical collector for blast furnace pre-cleaning	1,188 tpy (12mo rolling)	Limit on: FGB&CFURNACES baghouse and stove stacks R336.2803, R336.2804 -- PSD
AK Dearborn	1/1/1948, 10/1/2007 EUCFURNACE (part of FGB&CFURNACES), group of 4 stoves with a common			
AK Middleton	P925 No. 3 Blast Furnace 740 tons metal production/hr	For PM control: equipped with a casthouse baghouse, a settling chamber/dustcatcher (cyclone), a wet venturi scrubber system (Bischoff), stoves, and a blast furnace gas flare	None	
AM Cleveland	P903 Blast Furnace C5	equipped with a venturi scrubber for cleaning reusable blast furnace gas, natural gas suppression, oxygen enrichment, dirty and clean gas bleeders, and flue dust handling with passive emission control (PEC) system, and flare	33 lb/hr	from the blast furnace casthouse when combusting coke oven gas d. These emission limitations are not applicable because coke oven gas is no longer capable of being burned in this emissions unit.
AM Cleveland			53 lb/hr	from the blast furnace stoves when combusting coke oven gas d. These emission limitations are not applicable because coke oven gas is no longer capable of being burned in this emissions unit.
AM Cleveland	P904 Blast Furnace C6	equipped with a venturi scrubber for cleaning reusable blast furnace gas, natural gas suppression, oxygen enrichment, dirty and clean gas bleeders, and flue dust handling with passive emission control (PEC) system and a flare	33 lb/hr	A maximum of 390 grains of hydrogen sulfide per 100 dry standard cubic feet of coke oven gas, and the daily average not to exceed 33 lbs of SO2 per hour from the blast furnace casthouse when combusting coke oven gas.
AM Cleveland			53 lb/hr	Maximum of 390 grains of hydrogen sulfide per 100 dscf of coke oven gas and the daily average not to exceed 53 lbs SO2/hr from the blast furnace stoves when combusting coke oven gas.
USS Edgar Thompson	P001a Blast Furnace No. 1 Casthouse 1,752,000 tpy (production capacity) Coke, Iron-bearing materials, fluxes	Stack S002, Casthouse Baghouse (shared between P001a and P002a)	None	
USS Edgar Thompson	P002a Blast Furnace No. 3 Casthouse 1,752,000 tpy (production capacity) Coke, Iron-bearing materials, fluxes	Stack S002, Casthouse Baghouse (shared between P001a and P002a)	None	
USS Edgar Thompson	P001b Blast Furnace No. 1 Stoves 495 MMBtu/hr BFG, COG, Natural Gas	Stack S001, Dust Catch/Venturi scrubber for BFG cleaning	1. 353.03 lb/hr 2. 108.41 tpy 3. A = 1.7 E^(-0.14)	1. Applies to each set of stoves (No. 1 Blast furnace stoves & No. 3 Blast furnace stoves) Permit References: (§2104.03.a.2.B, §2104.02.b, §2103.12.a.2.B)
USS Edgar Thompson	P002b Base Furnace No. 3 Stoves 495 MMBtu/hr BFG, COG, Natural Gas	Stack S004, Dust Catch/Venturi scrubber for BFG cleaning		
USS Edgar Thompson	P001c BFG Flare 3 MMcfh BFG	Stack S003	None	
USS East Chicago	Facility does not have a blast furnace			

Appendix C

Unit-specific Screening Level Cost Summary for SO_2 Emission Control Measures

Appendix C.1

Battery No. 1 Underfire

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.1 – Table C.1-1: Cost Summary
Battery No. 1 Underfire
SO_2 Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Total Annualized Cost $/yr	Pollution Control Cost $/ton
Spray Dry Absorber (SDA)	90%	167.5	1507.4	$64,478,506	$9,527,094	$6,320

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.1 – Table C.1-2: Summary of Utility, Chemical and Supply Costs
Battery No. 1 Underfire

Operating Unit:	Battery No. 1 Underfire		**Study Year**	2020
Emission Unit Number				
Stack/Vent Number				

Item	2020 Unit Cost	Units	Cost	Year	Data Source	Notes
Operating Labor	68	$/hr	60	2016	EPA SCR Control Cost Manual Spreadsheet	
Maintenance Labor	68	$/hr				Assumed to be equivalent to operating labor
Installation Labor	68	$/hr				Assumed to be equivalent to operating labor
Electricity	0.07	$/kwh			2016-2019 EIA Average prices for the industrial sector in Indiana	
Natural Gas	6.15	$/kscf			2014-2018 EIA Average prices for the Industrial sector in Indiana (latest available 8/20/2020)	
Compressed Air	0.48	$/kscf	0.38	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Chemicals & Supplies						
Lime	183.68	$/ton	145.00	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Trona	285.00	$/ton		2020	Reagent cost for trona from another Barr Engineering Co. Project.	
Fabric Filter Bags	228.02	$/bag	180	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Other						
Sales Tax	7%			2020	Indiana sales tax rate	
Interest Rate	5.50%			2016	EPA SCR Control Cost Manual Spreadsheet	
Solid Waste Disposal	63.34	$/ton	50	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Contingencies	10%	of purchased equip cost (B)			EPA Cost Control Cost Manual Chapter 2	Suggested contingency range of 5% to 15% of total capital investment
Markup on capital investment (retrofit factor)	0%				EPA Cost Control Cost Manual Chapter 2	
Operating Information						
Annual Op. Hrs	8,760	Hours			Emission Inventory Data	
Utilization Rate	100%				Assumed	
Design Capacity	465.0	MMBTU/hr			Boiler Design Capacity	
Equipment Life	20	yrs			Assumed	
Temperature	385	Deg F			Performance test data	
Moisture Content	14.4%				Performance test data	
Actual Flow Rate	177,000	acfm			Performance test data	
Standardized Flow Rate	110,599	scfm @ 68º F	103,058	scfm @ 32º F	Calculated Value	
Dry Std Flow Rate	93,000	dscfm @ 68º F			Performance test data	
Plant Elevation	610	Feet above sea level				Plant elevation
	Baseline Emissions		**lb/hr**	**ton/year**		
Pollutant	**Lb/Hr**	**Ton/Year**	**ppmv**	**ppmv**	**lb/mmbtu**	
Nitrous Oxides (NOx)	811.0	3,552.0	1216	1216.1		Emission inventory data
Sulfur Dioxides (SO2)	382.4	1,674.9	412	411.9		Emission inventory data
SDA - SO_2 Control Efficiency	90%				EPA fact sheet for flue gas desulfurization (new installations) https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf	

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.1 – Table C.1-3: SO_2 Control Spray Dry Absorber (SDA)

Battery No. 1 Underfire

Operating Unit: **Battery No. 1 Underfire**

Emission Unit Number	0		Stack/Vent Number	0	
Design Capacity	465	MMBtu/hr	Standardized Flow Rate	103,058	scfm @ 32º F
Utilization Rate	100%		Temperature	385	Deg F
Annual Operating Hours	8,760	Hours	Moisture Content	14.4%	
Annual Interest Rate	5.5%		Actual Flow Rate	177,000	acfm
Equipment Life	20	yrs	Standardized Flow Rate	110,599	scfm @ 68º F
			Dry Std Flow Rate	93,000	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**23,385,502**
Purchased Equipment Total (B)	22%	of control device cost (A)	**28,530,312**
Installation - Standard Costs	74%	of purchased equip cost (B)	21,112,431
Installation - Site Specific Costs			NA
Installation Total			21,112,431
Total Direct Capital Cost, DC			49,642,744
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	14,835,762
Total Capital Investment (TCI) = DC + IC			**64,478,506**
Adjusted TCI for Replacment Parts			**64,282,882**
TCI with Retrofit Factor			**64,282,882**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	1,313,341
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	8,213,753
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**9,527,094**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc.**	**Conc. Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10						0.0	-	NA
PM2.5						0.0	-	NA
Total Particulates						0.0	-	NA
Nitrous Oxides (NOx)						0.0	-	NA
Sulfur Dioxide (SO_2)		1,674.9	90%			167.5	1,507.4	6,320
Sulfuric Acid Mist						0.00	-	NA
Fluorides						0.0	-	NA
Volatile Organic Compounds (VOC)						0.0	-	NA
Carbon Monoxide (CO)						0.0	-	NA
Lead (Pb)						0.00	-	NA

Notes & Assumptions

1 Capital cost estimate based on mid-range of EPA spray dry fact sheet $/(MMBtu/hr): https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf
2 Costs scaled up to design airflow using the 6/10 power law
3 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NOX and SO2 Emission Controls

Appendix C.1 – Table C.1-3: SO_2 Control Spray Dry Absorber (SDA)

Battery No. 1 Underfire

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (A) [1]		**23,385,502**
Purchased Equipment Costs (A) - Absorber + packing + auxiliary equipment, EC		
Instrumentation	10% of control device cost (A)	2,338,550
State Sales Taxes	7.0% of control device cost (A)	1,636,985
Freight	5% of control device cost (A)	1,169,275
Purchased Equipment Total (B)	22%	**28,530,312**
Installation		
Foundations & supports	4% of purchased equip cost (B)	1,141,212
Handling & erection	50% of purchased equip cost (B)	14,265,156
Electrical	8% of purchased equip cost (B)	2,282,425
Piping	1% of purchased equip cost (B)	285,303
Insulation	7% of purchased equip cost (B)	1,997,122
Painting	4% of purchased equip cost (B)	1,141,212
Installation Subtotal Standard Expenses	74%	**21,112,431**
Other Specific Costs (see summary)		
Site Preparation, as required	N/A Site Specific	-
Buildings, as required	N/A Site Specific	-
Site Specific - Other	N/A Site Specific	-
Total Site Specific Costs		NA
Installation Total		**21,112,431**
Total Direct Capital Cost, DC		**49,642,744**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	2,853,031
Construction & field expenses	20% of purchased equip cost (B)	5,706,062
Contractor fees	10% of purchased equip cost (B)	2,853,031
Start-up	1% of purchased equip cost (B)	285,303
Performance test	1% of purchased equip cost (B)	285,303
Model Studies	N/A of purchased equip cost (B)	-
Contingencies	10% of purchased equip cost (B)	2,853,031
Total Indirect Capital Costs, IC	52% of purchased equip cost (B)	**14,835,762**
Total Capital Investment (TCI) = DC + IC		**64,478,506**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		**64,282,882**
Total Capital Investment (TCI) with Retrofit Factor	0%	**64,282,882**
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	67.53 $/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 100% utilization	147,892
Supervisor	15% of Op., 0.0 , 8760 hr/yr, 100% utilization	22,184
Maintenance		
Maintenance Labor	67.53 $/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 100% utilization	73,946
Maintenance Materials	100% of maintenance labor costs	73,946
Utilities, Supplies, Replacements & Waste Management		
Electricity	0.07 $/kwh, 320.4 kW-hr, 8760 hr/yr, 100% utilization	204,800
Compressed Air	0.48 $/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization	89,565
N/A		-
SW Disposal	63.34 $/ton, 0.4 ton/hr, 8760 hr/yr, 100% utilization	212,215
Lime	183.68 $/ton, 517.4 lb/hr, 8760 hr/yr, 100% utilization	416,284
Filter Bags	228.02 $/bag, 704 bags, 8760 hr/yr, 100% utilization	72,509
N/A		
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
Total Annual Direct Operating Costs		**1,313,341**
Indirect Operating Costs		
Overhead	60% of total labor and material costs	190,780
Administration (2% total capital costs)	2% of total capital costs (TCI)	1,285,658
Property tax (1% total capital costs)	1% of total capital costs (TCI)	642,829
Insurance (1% total capital costs)	1% of total capital costs (TCI)	642,829
Capital Recovery	0.0837 for a 20- year equipment life and a 5.5% interest rate	5,451,657
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**8,213,753**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**9,527,094**

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NOX and SO2 Emission Controls
Appendix C.1 – Table C.1-3: SO_2 Control Spray Dry Absorber (SDA)
Battery No. 1 Underfire

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:	**Filter Bags**		
Equipment Life	3	years	
CRF	0.3707		
Rep part cost per unit	228.02	$/bag	
Amount Required	704		
Total Rep Parts Cost	179,778	Cost adjusted for freight & sales tax	
Installation Labor	15,846	10 min per bag	EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**195,624**		
Annualized Cost	**72,509**		

Electrical Use

	Flow acfm	D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	177,000	10.00			2,806,441	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total					2,806,441	

Reagents and Other Operating Costs

Lime Use Rate	1.30	lb-mole CaO/lb-mole SO2	517.43 lb/hr Lime
Solid Waste Disposal	3,350	ton/yr GSA unreacted sorbent and reaction byproducts	

Operating Cost Calculations

Utilization Rate	100%	Annual Operating Hours		8,760			
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	2,190	$ 147,892	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 100% utilization
Supervisor	15%	of Op.			NA	$ 22,184	of Op., 0.0 , 8760 hr/yr, 100% utilization
Maintenance							
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	1,095	$ 73,946	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 100% utilization
Maint Mtls	100	% of Maintenance Labor			NA	$ 73,946	% of Maintenance Labor, 0.0 , 8760 hr/yr, 100% utilization
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.073	$/kwh	320.4	kW-hr	2,806,441	$ 204,800	$/kwh, 320.4 kW-hr, 8760 hr/yr, 100% utilization
Compressed Air	0.481	$/kscf	2	scfm/kacfm	186,062	$ 89,565	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization
Water	5.129	$/mgal		gpm			$/mgal, 0 gpm, 8760 hr/yr, 100% utilization
SW Disposal	63.34	$/ton	0.38	ton/hr	3,350	$ 212,215	$/ton, 0.4 ton/hr, 8760 hr/yr, 100% utilization
Lime	183.68	$/ton	517.4	lb/hr	2,266	$ 416,284	$/ton, 517.4 lb/hr, 8760 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	704	bags	N/A	$ 72,509	$/bag, 704 bags, 8760 hr/yr, 100% utilization

Appendix C.2

Battery No. 2 Underfire

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.2 – Table C.2-1: Cost Summary
Battery No. 2 Underfire
SO_2 Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Total Annualized Cost $/yr	Pollution Control Cost $/ton
Spray Dry Absorber (SDA)	90%	185.4	1668.4	$58,238,651	$8,782,589	$5,264

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.2 – Table C.2-2: Summary of Utility, Chemical and Supply Costs

Battery No. 2 Underfire

Operating Unit:	Battery No. 2 Underfire	**Study Year**	2020
Emission Unit Number			
Stack/Vent Number			

Item	2020 Unit Cost	Units	Cost	Year	Data Source	Notes
Operating Labor	68	$/hr	60	2016	EPA SCR Control Cost Manual Spreadsheet	
Maintenance Labor	68	$/hr				Assumed to be equivalent to operating labor
Installation Labor	68	$/hr				Assumed to be equivalent to operating labor
Electricity	0.07	$/kwh			2016-2019 EIA Average prices for the industrial sector in Indiana	
Natural Gas	6.15	$/kscf			2014-2018 EIA Average prices for the Industrial sector in Indiana (latest available 8/20/2020)	
Compressed Air	0.48	$/kscf	0.38	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Chemicals & Supplies						
Lime	183.68	$/ton	145.00	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Trona	285.00	$/ton		2020	Reagent cost for trona from another Barr Engineering Co. Project.	
Fabric Filter Bags	228.02	$/bag	180	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Other						
Sales Tax	7%			2020	Indiana sales tax rate	
Interest Rate	5.50%			2016	EPA SCR Control Cost Manual Spreadsheet	
Solid Waste Disposal	63.34	$/ton	50	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Contingencies	10%	of purchased equip cost (B)			EPA Cost Control Cost Manual Chapter 2	Suggested contingency range of 5% to 15% of total capital investment
Markup on capital investment (retrofit factor)	0%				EPA Cost Control Cost Manual Chapter 2	
Operating Information						
Annual Op. Hrs	8,760	Hours			Emission Inventory Data	
Utilization Rate	100%				Assumed	
Design Capacity	420.0	MMBTU/hr			Boiler Design Capacity	
Equipment Life	20	yrs			Assumed	
Temperature	385	Deg F			Performance test data	
Moisture Content	14.4%				Performance test data	
Actual Flow Rate	160,000	acfm			Performance test data	
Standardized Flow Rate	99,976	scfm @ 68º F	93,160	scfm @ 32º F	Calculated Value	
Dry Std Flow Rate	94,000	dscfm @ 68º F			Performance test data	
Plant Elevation	610	Feet above sea level				Plant elevation
	Baseline Emissions		**lb/hr**	**ton/year**		
Pollutant	**Lb/Hr**	**Ton/Year**	**ppmv**	**ppmv**	**lb/mmbtu**	
Nitrous Oxides (NOx)	42.5	186.0	63	63.0		Emission inventory data
Sulfur Dioxides (SO2)	423.2	1,853.8	451	451.0		Emission inventory data
SDA - SO_2 Control Efficiency	90%				EPA fact sheet for flue gas desulfurization (new installations) https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf	

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.2 – Table C.2-3: SO_2 Control Spray Dry Absorber (SDA)

Battery No. 2 Underfire

Operating Unit: **Battery No. 2 Underfire**

Emission Unit Number	0		Stack/Vent Number	0	
Design Capacity	420	MMBtu/hr	Standardized Flow Rate	93,160	scfm @ 32º F
Utilization Rate	100%		Temperature	385	Deg F
Annual Operating Hours	8,760	Hours	Moisture Content	14.4%	
Annual Interest Rate	5.5%		Actual Flow Rate	160,000	acfm
Equipment Life	20	yrs	Standardized Flow Rate	99,976	scfm @ 68º F
			Dry Std Flow Rate	94,000	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**21,122,389**
Purchased Equipment Total (B)	22%	of control device cost (A)	**25,769,315**
Installation - Standard Costs	74%	of purchased equip cost (B)	19,069,293
Installation - Site Specific Costs			NA
Installation Total			19,069,293
Total Direct Capital Cost, DC			44,838,607
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	13,400,044
Total Capital Investment (TCI) = DC + IC			**58,238,651**
Adjusted TCI for Replacment Parts			**58,061,815**
TCI with Retrofit Factor			**58,061,815**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	1,345,217
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	7,437,372
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**8,782,589**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc.**	**Conc. Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10						0.0	-	NA
PM2.5						0.0	-	NA
Total Particulates						0.0	-	NA
Nitrous Oxides (NOx)						0.0	-	NA
Sulfur Dioxide (SO_2)		1,853.8	90%			185.4	1,668.4	5,264
Sulfuric Acid Mist						0.00	-	NA
Fluorides						0.0	-	NA
Volatile Organic Compounds (VOC)						0.0	-	NA
Carbon Monoxide (CO)						0.0	-	NA
Lead (Pb)						0.00	-	NA

Notes & Assumptions

1. Capital cost estimate based on mid-range of EPA spray dry fact sheet $/(MMBtu/hr): https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf
2. Costs scaled up to design airflow using the 6/10 power law
3. Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NOX and SO2 Emission Controls
Appendix C.2 – Table C.2-3: SO_2 Control Spray Dry Absorber (SDA)
Battery No. 2 Underfire

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (A) [1]		**21,122,389**
Purchased Equipment Costs (A) - Absorber + packing + auxiliary equipment, EC		
Instrumentation	10% of control device cost (A)	2,112,239
State Sales Taxes	7.0% of control device cost (A)	1,478,567
Freight	5% of control device cost (A)	1,056,119
Purchased Equipment Total (B)	22%	**25,769,315**
Installation		
Foundations & supports	4% of purchased equip cost (B)	1,030,773
Handling & erection	50% of purchased equip cost (B)	12,884,657
Electrical	8% of purchased equip cost (B)	2,061,545
Piping	1% of purchased equip cost (B)	257,693
Insulation	7% of purchased equip cost (B)	1,803,852
Painting	4% of purchased equip cost (B)	1,030,773
Installation Subtotal Standard Expenses	74%	**19,069,293**
Other Specific Costs (see summary)		
Site Preparation, as required	N/A Site Specific	-
Buildings, as required	N/A Site Specific	-
Site Specific - Other	N/A Site Specific	-
Total Site Specific Costs		NA
Installation Total		**19,069,293**
Total Direct Capital Cost, DC		**44,838,607**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	2,576,931
Construction & field expenses	20% of purchased equip cost (B)	5,153,863
Contractor fees	10% of purchased equip cost (B)	2,576,931
Start-up	1% of purchased equip cost (B)	257,693
Performance test	1% of purchased equip cost (B)	257,693
Model Studies	N/A of purchased equip cost (B)	-
Contingencies	10% of purchased equip cost (B)	2,576,931
Total Indirect Capital Costs, IC	52% of purchased equip cost (B)	**13,400,044**
Total Capital Investment (TCI) = DC + IC		**58,238,651**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		**58,061,815**
Total Capital Investment (TCI) with Retrofit Factor	0%	**58,061,815**
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	67.53 \$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 100% utilization	147,892
Supervisor	15% of Op., 0.0 , 8760 hr/yr, 100% utilization	22,184
Maintenance		
Maintenance Labor	67.53 \$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 100% utilization	73,946
Maintenance Materials	100% of maintenance labor costs	73,946
Utilities, Supplies, Replacements & Waste Management		
Electricity	0.07 \$/kwh, 289.6 kW-hr, 8760 hr/yr, 100% utilization	185,130
Compressed Air	0.48 \$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization	80,963
N/A		-
SW Disposal	63.34 \$/ton, 0.4 ton/hr, 8760 hr/yr, 100% utilization	234,875
Lime	183.68 \$/ton, 572.7 lb/hr, 8760 hr/yr, 100% utilization	460,736
Filter Bags	228.02 \$/bag, 636 bags, 8760 hr/yr, 100% utilization	65,545
N/A		
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
Total Annual Direct Operating Costs		**1,345,217**
Indirect Operating Costs		
Overhead	60% of total labor and material costs	190,780
Administration (2% total capital costs)	2% of total capital costs (TCI)	1,161,236
Property tax (1% total capital costs)	1% of total capital costs (TCI)	580,618
Insurance (1% total capital costs)	1% of total capital costs (TCI)	580,618
Capital Recovery	0.0837 for a 20- year equipment life and a 5.5% interest rate	4,924,119
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**7,437,372**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**8,782,589**

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NOX and SO2 Emission Controls

Appendix C.2 – Table C.2-3: SO_2 Control Spray Dry Absorber (SDA)

Battery No. 2 Underfire

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:	**Filter Bags**		
Equipment Life	3	years	
CRF	0.3707		
Rep part cost per unit	228.02	$/bag	
Amount Required	636		
Total Rep Parts Cost	162,511	Cost adjusted for freight & sales tax	
Installation Labor	14,324	10 min per bag	EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**176,836**		
Annualized Cost	**65,545**		

Electrical Use

	Flow acfm	D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	160,000	10.00			2,536,896	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total					2,536,896	

Reagents and Other Operating Costs

Lime Use Rate	1.30	lb-mole CaO/lb-mole SO2	572.68 lb/hr Lime
Solid Waste Disposal	3,708	ton/yr GSA unreacted sorbent and reaction byproducts	

Operating Cost Calculations

Utilization Rate	100%	Annual Operating Hours		8,760			
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	2,190	$ 147,892	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 100% utilization
Supervisor	15%	of Op.			NA	$ 22,184	of Op., 0.0 , 8760 hr/yr, 100% utilization
Maintenance							
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	1,095	$ 73,946	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 100% utilization
Maint Mtls	100	% of Maintenance Labor			NA	$ 73,946	% of Maintenance Labor, 0.0 , 8760 hr/yr, 100% utilization
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.073	$/kwh	289.6	kW-hr	2,536,896	$ 185,130	$/kwh, 289.6 kW-hr, 8760 hr/yr, 100% utilization
Compressed Air	0.481	$/kscf	2	scfm/kacfm	168,192	$ 80,963	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization
Water	5.129	$/mgal		gpm			$/mgal, 0 gpm, 8760 hr/yr, 100% utilization
SW Disposal	63.34	$/ton	0.42	ton/hr	3,708	$ 234,875	$/ton, 0.4 ton/hr, 8760 hr/yr, 100% utilization
Lime	183.68	$/ton	572.7	lb/hr	2,508	$ 460,736	$/ton, 572.7 lb/hr, 8760 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	636	bags	N/A	$ 65,545	$/bag, 636 bags, 8760 hr/yr, 100% utilization

Appendix C.3

Coke Oven Gas Desulfurization

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.3 – Table C.3-1: Cost Summary
Coke Oven Gas Desulfurization
SO_2 Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Total Annualized Cost $/yr	Pollution Control Cost $/ton
Coke Oven Gas Desulfurization	86.4%	1098.9	6997.1	$123,673,000	$27,854,000	$4,000

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.3 – Table C.3-2: Summary of Utility, Chemical and Supply Costs

Coke Oven Gas Desulfurization

Operating Unit:	Coke Oven Gas Desulfurization	**Study Year**	2020
Emission Unit Number	NA		
Stack/Vent Number	NA		

Item	2020 Unit Cost	Units	Cost	Year	Data Source	Notes
Operating Labor	68	$/hr	60	2016	EPA SCR Control Cost Manual Spreadsheet	
Maintenance Labor	68	$/hr				Assumed to be equivalent to operating labor
Installation Labor	68	$/hr				Assumed to be equivalent to operating labor
Electricity	0.07	$/kwh			2016-2019 EIA Average prices for the industrial sector in Indiana	
Steam	5.54	$/klb	4.00	2009	2014-2018 EIA Average prices for the Industrial sector in Indiana (latest available 8/20/2020)	
Amine	10.55	$/gallon	7.62	2009	Engineering cost estimate for desulfurization process	
Caustic	27.68	$/gallon	20.00	2009	Engineering cost estimate for desulfurization process	
Glycol	1.38	$/gallon	1.00	2009	Engineering cost estimate for desulfurization process	
Anti-Foam - Annual Cost	14,534	$/yr	10,500	2009	Engineering cost estimate for desulfurization process	
Corrosion Inhibitor - Annual Cost	41,527	$/yr	30,000	2009	Engineering cost estimate for desulfurization process	
Cooling Tower Chemicals - Annual Cost	17,303	$/yr	12,500	2009	Engineering cost estimate for desulfurization process	
Hot Feed Water Chemicals - Annual Cost	12,458	$/yr	9,000	2009	Engineering cost estimate for desulfurization process	
Reclaimer waste	1.25	$/gallon	0.9	2009	Engineering cost estimate for desulfurization process	
Maintenance Labor - Annual Cost	415,270	$/yr	300,000.0	2009	Engineering cost estimate for desulfurization process	
Water	5.13	$/mgal	4.17	2013	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Wastewater Disposal, Biological Treatment	6.47	$/mgal	3.80	2002	EPA Cost Control Cost Manual	
Compressed Air	0.48	$/kscf	0.38	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Chemicals & Supplies						
Lime	183.68	$/ton	145.00	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Trona	285.00	$/ton		2020	Reagent cost for trona from another Barr Engineering Co. Project.	
Fabric Filter Bags	228.02	$/bag	180	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Other						
Sales Tax	7%			2020	Indiana sales tax rate	
Interest Rate	5.50%			2016	EPA SCR Control Cost Manual Spreadsheet	
Solid Waste Disposal	63.34	$/ton	50	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Contingencies	25%	of purchased equip cost (B)			Site-specific estimate given several project unknowns and complexities	
Markup on capital investment (retrofit factor)	0%				EPA Cost Control Cost Manual Chapter 2	
Operating Information						
Annual Op. Hrs	8,760	Hours			Emission Inventory Data	
Utilization Rate	100%				Estimate from Engineering	
Equipment Life	20	yrs			Assumed	
	Baseline Emissions					
Pollutant	**Ton/Year**					
Sulfur Dioxides (SO_2)	8,096.0				Emission inventory data	
SO_2 Reduction	86.4%				Design basis for COG desulfurization plant 90% Control Efficiency 97% Reliability 99% control from sulfur plant	

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.3 – Table C.3-3: COG Desulfurization Plant (SO_2 Control)

Coke Oven Gas Desulfurization

Operating Unit: **Coke Oven Gas Desulfurization**

Expected Utilization Rate	100%	
Expected Annual Hours of Operation	8,760	Hours

CONTROL EQUIPMENT COSTS

Capital Costs		
Purchased Equipment		53,247,000
Site Preparation and Engineering		11,704,000
Construction		30,501,000
Startup Costs		3,486,000
Contingency		24,735,000
Total Capital Investment (TCI)		**123,673,000**
Operating Costs		
Total Annual Direct Operating Costs	Labor, supervision, materials, replacement parts, utilities, etc.	10,835,000
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	17,019,000
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**27,854,000**

Emission Control Cost Calculation

Pollutant	Baseline Emis. T/yr	Cont. Emis. lb/hr	Cont. Emis. lb/MMBtu	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
PM10		-			-	NA
Total Particulates		-			-	NA
Nitrous Oxides (NOx)		-			-	NA
Sulfur Dioxide (SO_2)	8,096			1,099	6,997	4,000

Notes & Assumptions

1 COG Desulfurization costs are based on a previous engineering study specific to this facility and have been scaled for inflation

2 COG Desulfurization would require several process units and upgrades, including:

Absorber-Desorber Unit	Piping
Reflux Unit	Electrical including upgrades as needed
Aromatic Removal Unit	Utilities including upgrades as needed
HCN Destruct Unit	Control building
Sulfur Recovery Unit	

3 COG Desulfurization operating costs were evaluated as part of the engineering study and are based on benchmarking and comparison to similar sources

4 COG Desulfurization controlled emissions assumes 90% SO_2 reduction in COG for downstream combustion sources, 97% reliability, and 99% control of sulfur plant.

5 Investment risk associated with the contingency is presented in Table C.3-4

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NOX and SO2 Emission Controls
Appendix C.3 – Table C.3-3: COG Desulfurization Plant (SO_2 Control)
Coke Oven Gas Desulfurization

CAPITAL COSTS
(all values rounded to 1,000s)

Purchased Equipment		
Purchased Equipment Cost (A)		53,247,000
Sales Taxes	included	0
Freight	included	0
Purchased Equipment Total		**53,247,000**
Site Preparation and Engineering		
Site Preparation		2,484,000
Engineering		9,220,000
Site Preparation and Engineering Total		**11,704,000**
Construction		
Construction		29,896,000
Project assistance		222,000
Construction Coordination		383,000
Construction Total		**30,501,000**
Startup Costs		
Startup and commissioning		1,520,000
Spares		1,769,000
Training		197,000
Startup Total		**3,486,000**
Total		**98,938,000**
Total Capital Investment (TCI) with Contingency	25%	**123,673,000**

OPERATING COSTS
(all values rounded to 1,000s)
Direct Annual Operating Costs, DC

Operating Labor			
Operator	67.53	$/Hr, 24.0 hr/8 hr shift, 8760 hr/yr	1,775,000
Supervisor	15%	15% of Operator Costs	266,000
Maintenance (2)			
Maintenance Labor		Engineering estimate	415,000
Maintenance Materials	100%	of maintenance labor costs	415,000
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.07	$/kwh, 708 kW-hr, 8760 hr/yr, 100% utilization	452,000
Steam	5.54	$/klb, 76,205 lb/hr, 8760 hr/yr, 100% utilization	3,696,000
Cooling Water	5.13	$/kgal, 294 gpm, 8760 hr/yr, 100% utilization	793,000
WWTP Biological Treatment	6.47	$/kgal, 50 gpm, 8760 hr/yr, 100% utilization	170,000
Amine	10.55	$/gallon, 600 gpd, 8760 hr/yr, 100% utilization	2,310,000
Caustic	27.68	$/gallon, 12 gpd, 8760 hr/yr, 100% utilization	121,000
Glycol	1.38	$/gallon, 73 gpd, 8760 hr/yr, 100% utilization	37,000
Anti-Foam - Annual Cost		Engineering estimate	15,000
Corrosion Inhibitor - Annual Cost		Engineering estimate	42,000
Cooling Tower Chemicals - Annual Cost		Engineering estimate	17,000
Hot Feed Water Chemicals - Annual Cost		Engineering estimate	12,000
Reclaimer waste	1.25	Engineering estimate	299,000
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**10,835,000**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	1,723,000
Administration (2% total capital costs)	2%	of total capital costs (TCI)	2,473,000
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	1,237,000
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	1,237,000
Capital Recovery	8%	for a 20- year equipment life and a 5.5% interest rate	10,349,000
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**17,019,000**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**27,854,000**

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NOX and SO2 Emission Controls

Appendix C.3 – Table C.3-3: COG Desulfurization Plant (SO_2 Control)

Coke Oven Gas Desulfurization

Capital Recovery Factors	
Primary Installation	
Interest Rate	5.50%
Equipment Life	20 years
CRF	0.0837

Replacement Parts & Equipment:
N/A

Replacement Parts & Equipment:
N/A

Electrical Use
N/A

Reagent Use & Other Operating Costs

Operating Cost Calculations **Annual hours of operation:** **8,760**

Utilization Rate: **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	67.53	$/Hr	24.0	hr/8 hr shift	26,280	1,775,000	$/Hr, 24.0 hr/8 hr shift, 8760 hr/yr
Supervisor	15%	of Op.			NA	266,000	15% of Operator Costs
Maintenance							
Maint Labor						415,000	Engineering estimate
Maint Mtls	100	% of Maintenance Labor			NA	415,000	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.073	$/kwh	707.8	kW-hr	6,199,890	452,000	$/kwh, 708 kW-hr, 8760 hr/yr, 100% utilization
Steam	5.54	$/klb	76205	lb/hr	667,556	3,696,000	$/klb, 76,205 lb/hr, 8760 hr/yr, 100% utilization
Cooling Water	5.13	$/kgal	294.0	gpm	154,526	793,000	$/kgal, 294 gpm, 8760 hr/yr, 100% utilization
WWTP Biological Treatı	6.47	$/kgal	50.0	gpm	26,280	170,000	$/kgal, 50 gpm, 8760 hr/yr, 100% utilization
Amine	10.55	$/gallon	600	gpd	219,000	2,310,000	$/gallon, 600 gpd, 8760 hr/yr, 100% utilization
Caustic	27.68	$/gallon	12.0	gpd	4,380	121,000	$/gallon, 12 gpd, 8760 hr/yr, 100% utilization
Glycol	1.38	$/gallon	73.4	gpd	26,806	37,000	$/gallon, 73 gpd, 8760 hr/yr, 100% utilization
Anti-Foam - Annual Cost						15,000	Engineering estimate
Corrosion Inhibitor - Annual Cost						42,000	Engineering estimate
Cooling Tower Chemicals - Annual Cost						17,000	Engineering estimate
Hot Feed Water Chemicals - Annual Cost						12,000	Engineering estimate
Reclaimer waste	1.2	$/gallon	20000	gallon/month	240,000	299,000	Engineering estimate

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NOX and SO2 Emission Controls
Appendix C.3 – Table C.3-4: COG Desulfurization Plant (SO_2 Control)
Coke Oven Gas Desulfurization

Contingency Assessment

The following risks were considered for the ArcelorMittal Burns Harbor Coke Plant Desulfurization Plant project and comprise the level of contingency build to apply overall to the project.

1	Cold weather conditions along the Lake Michigan lake front - high winds and 10 degrees cooler than inland - for winter months. Reduced construction efficiency as a result.
2	Union cost premium - Expertise and talent are a premium with the AFL-CIO trades. There are also limitations to worker utilization, which can impede on overall efficiency.
3	Construction worker rates - This area is being impacted by high construction worker labor fees. While the base estimate includes these rates, where extra work is involved, the extra construction work is disproportionately higher in cost.
4	Precious metals - The system would require ample amounts of titanium and other precious metals. With this market being controlled by foreign markets which are impacted by trade issues, the equipment cost could be disproportionately inflated as a result of precious metals costs.
5	Technology - Incremental technology advances since the engineering study was completed may be available that provide incremental benefits, but also incremental costs.
6	Development Detail - The level of development effort for the engineering study was identified as "Step 0", with less than 0.5% of total project value exhausted as development effort. This is a very low level for such a large project. While the project has been performed elsewhere previously, and many repeat costs are available, the development detail is substituted with a larger proportion of contingency to offset further spending on development.
7	Sub-surface - The site is brownfield, therefore, unexpected costs could be incurred when preparing the site for construction. This cost was not included and is typically the largest additional-cost category for a brownfield site (up to 15% of all extras are sub-surface).
8	Inflation - Pricing for equipment and installation could be upwards of 40% higher than norm if the project proceeds during a significant upcycle in business and/or if certain components/materials are in high global demand. This is above and beyond the normalized inflation rate that was considered.

Appendix C.4

Power Station Boiler No. 7

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.4 – Table C.4-1: Cost Summary
Power Station Boiler No. 7

SO_2 Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Total Annualized Cost $/yr	Pollution Control Cost $/ton
Spray Dry Absorber (SDA)	90%	90.1	810.7	$90,131,245	$13,025,113	$16,066
Dry Sorbent Injection (DSI)	70%	270.2	630.5	$20,036,476	$5,555,483	$8,800

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.4 – Table C.4-2: Summary of Utility, Chemical and Supply Costs
Power Station Boiler No. 7

Operating Unit:	Power Station Boiler No. 7	**Study Year**	2020
Emission Unit Number			
Stack/Vent Number			

Item	2020 Unit Cost	Units	Cost	Year	Data Source	Notes
Operating Labor	68	$/hr	60	2016	EPA SCR Control Cost Manual Spreadsheet	
Maintenance Labor	68	$/hr				Assumed to be equivalent to operating labor
Installation Labor	68	$/hr				Assumed to be equivalent to operating labor
Electricity	0.07	$/kwh			2016-2019 EIA Average prices for the industrial sector in Indiana	
Natural Gas	6.15	$/kscf			2014-2018 EIA Average prices for the Industrial sector in Indiana (latest available 8/20/2020)	
Compressed Air	0.48	$/kscf	0.38	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Chemicals & Supplies						
Lime	183.68	$/ton	145.00	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Trona	285.00	$/ton		2020	Reagent cost for trona from another Barr Engineering Co. Project.	
Fabric Filter Bags	228.02	$/bag	180	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Other						
Sales Tax	7%			2020	Indiana sales tax rate	
Interest Rate	5.50%			2016	EPA SCR Control Cost Manual Spreadsheet	
Solid Waste Disposal	63.34	$/ton	50	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Contingencies	10%	of purchased equip cost (B)			EPA Cost Control Cost Manual Chapter 2	Suggested contingency range of 5% to 15% of total capital investment
Markup on capital investment (retrofit factor)	0%				EPA Cost Control Cost Manual Chapter 2	
Operating Information						
Annual Op. Hrs	8,760	Hours			Emission Inventory Data	
Utilization Rate	100%				Assumed	
Design Capacity	650.0	MMBTU/hr			Boiler Design Capacity	
Equipment Life	20	yrs			Assumed	
Temperature	462	Deg F			Performance test data	
Moisture Content	10.9%				Performance test data	
Actual Flow Rate	439,519	acfm			Performance test data	
Standardized Flow Rate	251,699	scfm @ 68º F	234,537	scfm @ 32º F	Calculated Value	
Dry Std Flow Rate	221,045	dscfm @ 68º F			Performance test data	
Plant Elevation	610	Feet above sea level				Plant elevation
	Baseline Emissions		**lb/hr**	**ton/year**		
Pollutant	**Lb/Hr**	**Ton/Year**	**ppmv**	**ppmv**	**lb/mmbtu**	
Nitrous Oxides (NOx)	33.3	146.0	21	21.0		Emission inventory data
Sulfur Dioxides (SO2)	205.7	900.8	93	93.2		Emission inventory data
SDA - SO_2 Control Efficiency	90%				EPA fact sheet for flue gas desulfurization (new installations) https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf	
DSI - SO_2 Control Efficiency	70%				Control efficiency is based on trona as injected reagent.	

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.4 – Table C.4-3: SO_2 Control Spray Dry Absorber (SDA)

Power Station Boiler No. 7

Operating Unit: **Power Station Boiler No. 7**

Emission Unit Number	0		Stack/Vent Number	0	
Design Capacity	650	MMBtu/hr	Standardized Flow Rate	234,537	scfm @ 32º F
Utilization Rate	100%		Temperature	462	Deg F
Annual Operating Hours	8,760	Hours	Moisture Content	10.9%	
Annual Interest Rate	5.5%		Actual Flow Rate	439,519	acfm
Equipment Life	20	yrs	Standardized Flow Rate	251,699	scfm @ 68º F
			Dry Std Flow Rate	221,045	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**32,689,411**
Purchased Equipment Total (B)	22%	of control device cost (A)	**39,881,082**
Installation - Standard Costs	74%	of purchased equip cost (B)	29,512,001
Installation - Site Specific Costs			NA
Installation Total			29,512,001
Total Direct Capital Cost, DC			69,393,083
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	20,738,163
Total Capital Investment (TCI) = DC + IC			**90,131,245**
Adjusted TCI for Replacment Parts			**89,645,479**
TCI with Retrofit Factor			**89,645,479**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	1,566,988
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	11,458,125
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**13,025,113**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc.**	**Conc. Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10						0.0	-	NA
PM2.5						0.0	-	NA
Total Particulates						0.0	-	NA
Nitrous Oxides (NOx)						0.0	-	NA
Sulfur Dioxide (SO_2)		900.8	90%			90.1	810.7	16,066
Sulfuric Acid Mist						0.00	-	NA
Fluorides						0.0	-	NA
Volatile Organic Compounds (VOC)						0.0	-	NA
Carbon Monoxide (CO)						0.0	-	NA
Lead (Pb)						0.00	-	NA

Notes & Assumptions

1 Capital cost estimate based on mid-range of EPA spray dry fact sheet $/(MMBtu/hr): https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf
2 Costs scaled up to design airflow using the 6/10 power law
3 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.4 – Table C.4-3: SO_2 Control Spray Dry Absorber (SDA)

Power Station Boiler No. 7

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (A) [1]		**32,689,411**
Purchased Equipment Costs (A) - Absorber + packing + auxiliary equipment, EC		
Instrumentation	10% of control device cost (A)	3,268,941
State Sales Taxes	7.0% of control device cost (A)	2,288,259
Freight	5% of control device cost (A)	1,634,471
Purchased Equipment Total (B)	22%	**39,881,082**
Installation		
Foundations & supports	4% of purchased equip cost (B)	1,595,243
Handling & erection	50% of purchased equip cost (B)	19,940,541
Electrical	8% of purchased equip cost (B)	3,190,487
Piping	1% of purchased equip cost (B)	398,811
Insulation	7% of purchased equip cost (B)	2,791,676
Painting	4% of purchased equip cost (B)	1,595,243
Installation Subtotal Standard Expenses	74%	**29,512,001**
Other Specific Costs (see summary)		
Site Preparation, as required	N/A Site Specific	-
Buildings, as required	N/A Site Specific	-
Site Specific - Other	N/A Site Specific	-
Total Site Specific Costs		NA
Installation Total		**29,512,001**
Total Direct Capital Cost, DC		**69,393,083**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	3,988,108
Construction & field expenses	20% of purchased equip cost (B)	7,976,216
Contractor fees	10% of purchased equip cost (B)	3,988,108
Start-up	1% of purchased equip cost (B)	398,811
Performance test	1% of purchased equip cost (B)	398,811
Model Studies	N/A of purchased equip cost (B)	-
Contingencies	10% of purchased equip cost (B)	3,988,108
Total Indirect Capital Costs, IC	52% of purchased equip cost (B)	**20,738,163**
Total Capital Investment (TCI) = DC + IC		**90,131,245**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		**89,645,479**
Total Capital Investment (TCI) with Retrofit Factor	0%	**89,645,479**
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	67.53 $/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 100% utilization	147,892
Supervisor	15% of Op., 0.0 , 8760 hr/yr, 100% utilization	22,184
Maintenance		
Maintenance Labor	67.53 $/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 100% utilization	73,946
Maintenance Materials	100% of maintenance labor costs	73,946
Utilities, Supplies, Replacements & Waste Management		
Electricity	0.07 $/kwh, 795.5 kW-hr, 8760 hr/yr, 100% utilization	508,551
Compressed Air	0.48 $/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization	222,405
N/A		-
SW Disposal	63.34 $/ton, 0.2 ton/hr, 8760 hr/yr, 100% utilization	114,131
Lime	183.68 $/ton, 278.3 lb/hr, 8760 hr/yr, 100% utilization	223,882
Filter Bags	228.02 $/bag, 1,748 bags, 8760 hr/yr, 100% utilization	180,051
N/A		
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
Total Annual Direct Operating Costs		**1,566,988**
Indirect Operating Costs		
Overhead	60% of total labor and material costs	190,780
Administration (2% total capital costs)	2% of total capital costs (TCI)	1,792,910
Property tax (1% total capital costs)	1% of total capital costs (TCI)	896,455
Insurance (1% total capital costs)	1% of total capital costs (TCI)	896,455
Capital Recovery	0.0837 for a 20- year equipment life and a 5.5% interest rate	7,681,525
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**11,458,125**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**13,025,113**

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.4 – Table C.4-3: SO_2 Control Spray Dry Absorber (SDA)
Power Station Boiler No. 7

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:	**Filter Bags**		
Equipment Life	3	years	
CRF	0.3707		
Rep part cost per unit	228.02	$/bag	
Amount Required	1748		
Total Rep Parts Cost	446,417	Cost adjusted for freight & sales tax	
Installation Labor	39,349	10 min per bag	EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**485,766**		
Annualized Cost	**180,051**		

Electrical Use

	Flow acfm	D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	439,519	10.00			6,968,837	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total					6,968,837	

Reagents and Other Operating Costs

Lime Use Rate	1.30	lb-mole CaO/lb-mole SO2	278.28 lb/hr Lime
Solid Waste Disposal	1,802	ton/yr GSA unreacted sorbent and reaction byproducts	

Operating Cost Calculations

Utilization Rate	100%	Annual Operating Hours		8,760			
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	2,190	$ 147,892	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 100% utilization
Supervisor	15%	of Op.			NA	$ 22,184	of Op., 0.0 , 8760 hr/yr, 100% utilization
Maintenance							
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	1,095	$ 73,946	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 100% utilization
Maint Mtls	100	% of Maintenance Labor			NA	$ 73,946	% of Maintenance Labor, 0.0 , 8760 hr/yr, 100% utilization
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.073	$/kwh	795.5	kW-hr	6,968,837	$ 508,551	$/kwh, 795.5 kW-hr, 8760 hr/yr, 100% utilization
Compressed Air	0.481	$/kscf	2	scfm/kacfm	462,022	$ 222,405	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization
Water	5.129	$/mgal		gpm			$/mgal, 0 gpm, 8760 hr/yr, 100% utilization
SW Disposal	63.34	$/ton	0.21	ton/hr	1,802	$ 114,131	$/ton, 0.2 ton/hr, 8760 hr/yr, 100% utilization
Lime	183.68	$/ton	278.3	lb/hr	1,219	$ 223,882	$/ton, 278.3 lb/hr, 8760 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	1,748	bags	N/A	$ 180,051	$/bag, 1,748 bags, 8760 hr/yr, 100% utilization

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.4 – Table C.4-4: SO_2 Control Dry Sorbent Injection (DSI) with Baghouse
Power Station Boiler No. 7

Operating Unit: **Power Station Boiler No. 7**

Emission Unit Number			Stack/Vent Number		
Design Capacity	650	MMBtu/hr	Standardized Flow Rate	234,537	scfm @ 32º F
Utilization Rate	100%		Exhaust Temperature	462	Deg F
Annual Operating Hours	8,760	hr/yr	Exhaust Moisture Content	10.9%	
Annual Interest Rate	5.50%		Actual Flow Rate	439,519	acfm
Control Equipment Life	20	yrs	Standardized Flow Rate	251,699	scfm @ 68º F
Plant Elevation	610	ft	Dry Std Flow Rate	221,045	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs						
Direct Capital Costs						
Purchased Equipment (A)						**7,443,146**
Purchased Equipment Total (B)	22%	of control device cost (A)				**9,080,638**
Installation - Standard Costs	74%	of purchased equip cost (B)				6,719,672
Installation - Site Specific Costs						N/A
Installation Total						6,719,672
Total Direct Capital Cost, DC						15,800,310
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)				4,721,932
Total Capital Investment (TCI) = DC + IC						**20,036,476**
Adjusted TCI for Replacement Parts						20,036,476
Total Capital Investment (TCI) with Retrofit Factor						**20,036,476**
Operating Costs						
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.				2,706,554
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost				2,848,930
Total Annual Cost (Annualized Capital Cost + Operating Cost)						**5,555,483**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual Ton/Yr	Cont Eff %	Cont Emis Ton/Yr	Reduction Ton/Yr	Cont Cost $/Ton Rem
PM10						
PM2.5						
Total Particulates						
Nitrous Oxides (NOx)						
Sulfur Dioxide (SO2)	205.66	900.78	70%	270.23	630.55	$8,800
Sulfuric Acid Mist (H2SO4)						
Fluorides						
Volatile Organic Compounds (VOC)						
Carbon Monoxide (CO)						
Lead (Pb)						

Notes & Assumptions

1. Baghouse capital cost estimate based on EPA-R05-OAR-2010-0954-0079, ancillary equipment from other Barr Engineering projects
2. Costs scaled up to design airflow using the 6/10 power law
3. Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.4 – Table C.4-4: SO_2 Control Dry Sorbent Injection (DSI) with Baghouse
Power Station Boiler No. 7

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) [1]			**7,443,146**
Purchased Equipment Costs (A) - Injection System + auxiliary equipment, EC			
Instrumentation	10%	Included in vendor estimate	744,315
State Sales Taxes	7.0%	of control device cost (A)	521,020
Freight	5%	of control device cost (A)	372,157
Purchased Equipment Total (B)	22%		**9,080,638**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	363,226
Handling & erection	50%	of purchased equip cost (B)	4,540,319
Electrical	8%	of purchased equip cost (B)	726,451
Piping	1%	of purchased equip cost (B)	90,806
Insulation	7%	of purchased equip cost (B)	635,645
Painting	4%	Included in vendor estimate	363,226
Installation Subtotal Standard Expenses	74%		**6,719,672**
Other Specific Costs (see summary)			
Site Preparation, as required	N/A	Site Specific	
Buildings, as required	N/A	Site Specific	
Lost Production for Tie-In	N/A	Site Specific	
Total Site Specific Costs			N/A
Installation Total			**6,719,672**
Total Direct Capital Cost, DC			**15,800,310**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	908,064
Construction & field expenses	20%	of purchased equip cost (B)	1,816,128
Contractor fees	10%	of purchased equip cost (B)	908,064
Start-up	1%	of purchased equip cost (B)	90,806
Performance test	1%	of purchased equip cost (B)	90,806
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	908,064
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**4,721,932**
Total Capital Investment (TCI) = DC + IC			**20,522,242**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**20,036,476**
Total Capital Investment (TCI) with Retrofit Factor	0%		**20,036,476**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	67.53	$/Hr	147,892
Supervisor	0.15	of Op Labor	22,184
Maintenance			
Maintenance Labor	67.53	$/Hr	73,946
Maintenance Materials	100	% of Maintenance Labor	73,946
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.07	$/kwh, 477.3 kW-hr, 8760 hr/yr, 100% utilization	305,131
N/A			-
Compressed Air	0.48	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization	222,405
N/A			-
Solid Waste Disposal	63.34	$/ton, 0.5 ton/hr, 8760 hr/yr, 100% utilization	254,653
Trona	285.00	$/ton, 1,142.6 lb/hr, 8760 hr/yr, 100% utilization	1,426,346
Filter Bags	228.02	$/bag, 1,748 bags, 8760 hr/yr, 100% utilization	180,051
N/A			-
N/A			-
N/A			-
N/A			-
Total Annual Direct Operating Costs			**2,706,554**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	190,780
Administration (2% total capital costs)	2%	of total capital costs (TCI)	400,730
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	200,365
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	200,365
Capital Recovery	0.0837	for a 20-year equipment life and a 5.5% interest rate	1,676,639
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery costs	**2,848,930**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**5,555,483**

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.4 – Table C.4-4: SO_2 Control Dry Sorbent Injection (DSI) with Baghouse
Power Station Boiler No. 7

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment: **Filter Bags**

Equipment Life	3	years
CRF	0.3707	
Rep part cost per unit	228.02	$/bag
Amount Required	1748	Bags
Total Rep Parts Cost	446,417	Cost adjusted for freight, sales tax, and bag disposal
Installation Labor	39,349	20 min per bag
Total Installed Cost	**485,766**	
Annualized Cost	**180,051**	

Electrical Use

	Flow acfm	D P in H2O	kWhr/yr	
Blower	439,519	6.00	4,181,302	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total			4,181,302	

Reagent Use & Other Operating Costs

Trona use - 1.5 NSR	205.66	lb/hr SO2	1142.63	lb/hr Trona
Solid Waste Disposal	4,021	ton/yr DSI unreacted sorbent and reaction byproducts		

Operating Cost Calculations

Utilization Rate	100%	Annual Operating Hours		8,760			
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	2,190	$ 147,892	$/Hr, 2.0 hr/8 hr shift, 2,190 hr/yr
Supervisor	15%	of Op Labor			NA	$ 22,184	% of Operator Costs
Maintenance							
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	1,095	$ 73,946	$/Hr, 1.0 hr/8 hr shift, 1,095 hr/yr
Maint Mtls	100%	of Maintenance Labor			NA	$ 73,946	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.073	$/kwh	477.3	kW-hr	4,181,302	$ 305,131	$/kwh, 477.3 kW-hr, 8760 hr/yr, 100% utilization
Water			N/A	gpm			
Compressed Air	0.481	$/kscf	2.0	scfm/kacfm	462,022	$ 222,405	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization
Cooling Water			N/A	gpm			
Solid Waste Disposal	63.34	$/ton	0.5	ton/hr	4,021	$ 254,653	$/ton, 0.5 ton/hr, 8760 hr/yr, 100% utilization
Trona	285.00	$/ton	1,142.6	lb/hr	5,005	$ 1,426,346	$/ton, 1,142.6 lb/hr, 8760 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	1,748	bags	N/A	$ 180,051	$/bag, 1,748 bags, 8760 hr/yr, 100% utilization

Appendix C.5

Power Station Boiler No. 8

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.5 – Table C.5-1: Cost Summary
Power Station Boiler No. 8

SO_2 Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Total Annualized Cost $/yr	Pollution Control Cost $/ton
Spray Dry Absorber (SDA)	90%	65.1	585.9	$90,131,245	$12,700,296	$21,676
Dry Sorbent Injection (DSI)	70%	195.3	455.7	$17,155,347	$4,534,089	$9,900

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.5 – Table C.5-2: Summary of Utility, Chemical and Supply Costs

Power Station Boiler No. 8

Operating Unit:	Power Station Boiler No. 8	**Study Year**	2020
Emission Unit Number			
Stack/Vent Number			

Item	2020 Unit Cost	Units	Cost	Year	Data Source	Notes
Operating Labor	68	$/hr	60	2016	EPA SCR Control Cost Manual Spreadsheet	
Maintenance Labor	68	$/hr				Assumed to be equivalent to operating labor
Installation Labor	68	$/hr				Assumed to be equivalent to operating labor
Electricity	0.07	$/kwh			2016-2019 EIA Average prices for the industrial sector in Indiana	
Natural Gas	6.15	$/kscf			2014-2018 EIA Average prices for the Industrial sector in Indiana (latest available 8/20/2020)	
Compressed Air	0.48	$/kscf	0.38	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Chemicals & Supplies						
Lime	183.68	$/ton	145.00	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Trona	285.00	$/ton		2020	Reagent cost for trona from another Barr Engineering Co. Project.	
Fabric Filter Bags	228.02	$/bag	180	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Other						
Sales Tax	7%			2020	Indiana sales tax rate	
Interest Rate	5.50%			2016	EPA SCR Control Cost Manual Spreadsheet	
Solid Waste Disposal	63.34	$/ton	50	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Contingencies	10%	of purchased equip cost (B)			EPA Cost Control Cost Manual Chapter 2	Suggested contingency range of 5% to 15% of total capital investment
Markup on capital investment (retrofit factor)	0%				EPA Cost Control Cost Manual Chapter 2	
Operating Information						
Annual Op. Hrs	8,760	Hours			Emission Inventory Data	
Utilization Rate	100%				Assumed	
Design Capacity	650.0	MMBTU/hr			Boiler Design Capacity	
Equipment Life	20	yrs			Assumed	
Temperature	415	Deg F			Performance test data	
Moisture Content	12.8%				Performance test data	
Actual Flow Rate	341,000	acfm			Performance test data	
Standardized Flow Rate	205,769	scfm @ 68º F	191,739	scfm @ 32º F	Calculated Value	
Dry Std Flow Rate	175,000	dscfm @ 68º F			Performance test data	
Plant Elevation	610	Feet above sea level				Plant elevation
	Baseline Emissions		**lb/hr**	**ton/year**		
Pollutant	**Lb/Hr**	**Ton/Year**	**ppmv**	**ppmv**	**lb/mmbtu**	
Nitrous Oxides (NOx)	63.0	276.0	50	50.2		Emission inventory data
Sulfur Dioxides (SO2)	148.6	651.0	85	85.1		Emission inventory data
SDA - SO_2 Control Efficiency	90%				EPA fact sheet for flue gas desulfurization (new installations) https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf	
DSI - SO_2 Control Efficiency	70%				Control efficiency is based on trona as injected reagent.	

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.5 – Table C.5-3: SO_2 Control Spray Dry Absorber (SDA)

Power Station Boiler No. 8

Operating Unit: **Power Station Boiler No. 8**

Emission Unit Number	0		Stack/Vent Number	0	
Design Capacity	650	MMBtu/hr	Standardized Flow Rate	191,739	scfm @ 32º F
Utilization Rate	100%		Temperature	415	Deg F
Annual Operating Hours	8,760	Hours	Moisture Content	12.8%	
Annual Interest Rate	5.5%		Actual Flow Rate	341,000	acfm
Equipment Life	20	yrs	Standardized Flow Rate	205,769	scfm @ 68º F
			Dry Std Flow Rate	175,000	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**32,689,411**
Purchased Equipment Total (B)	22%	of control device cost (A)	**39,881,082**
Installation - Standard Costs	74%	of purchased equip cost (B)	29,512,001
Installation - Site Specific Costs			NA
Installation Total			29,512,001
Total Direct Capital Cost, DC			69,393,083
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	20,738,163
Total Capital Investment (TCI) = DC + IC			**90,131,245**
Adjusted TCI for Replacment Parts			**89,754,364**
TCI with Retrofit Factor			**89,754,364**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	1,269,063
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	11,431,233
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**12,700,296**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc.**	**Conc. Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10						0.0	-	NA
PM2.5						0.0	-	NA
Total Particulates						0.0	-	NA
Nitrous Oxides (NOx)						0.0	-	NA
Sulfur Dioxide (SO_2)		651.0	90%			65.1	585.9	21,676
Sulfuric Acid Mist						0.00	-	NA
Fluorides						0.0	-	NA
Volatile Organic Compounds (VOC)						0.0	-	NA
Carbon Monoxide (CO)						0.0	-	NA
Lead (Pb)						0.00	-	NA

Notes & Assumptions

1 Capital cost estimate based on mid-range of EPA spray dry fact sheet $/(MMBtu/hr): https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf

2 Costs scaled up to design airflow using the 6/10 power law

3 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)

4 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.5 – Table C.5-3: SO_2 Control Spray Dry Absorber (SDA)
Power Station Boiler No. 8

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (A) [1]		**32,689,411**
Purchased Equipment Costs (A) - Absorber + packing + auxiliary equipment, EC		
Instrumentation	10% of control device cost (A)	3,268,941
State Sales Taxes	7.0% of control device cost (A)	2,288,259
Freight	5% of control device cost (A)	1,634,471
Purchased Equipment Total (B)	22%	**39,881,082**
Installation		
Foundations & supports	4% of purchased equip cost (B)	1,595,243
Handling & erection	50% of purchased equip cost (B)	19,940,541
Electrical	8% of purchased equip cost (B)	3,190,487
Piping	1% of purchased equip cost (B)	398,811
Insulation	7% of purchased equip cost (B)	2,791,676
Painting	4% of purchased equip cost (B)	1,595,243
Installation Subtotal Standard Expenses	74%	**29,512,001**
Other Specific Costs (see summary)		
Site Preparation, as required	N/A Site Specific	-
Buildings, as required	N/A Site Specific	-
Site Specific - Other	N/A Site Specific	-
Total Site Specific Costs		NA
Installation Total		**29,512,001**
Total Direct Capital Cost, DC		**69,393,083**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	3,988,108
Construction & field expenses	20% of purchased equip cost (B)	7,976,216
Contractor fees	10% of purchased equip cost (B)	3,988,108
Start-up	1% of purchased equip cost (B)	398,811
Performance test	1% of purchased equip cost (B)	398,811
Model Studies	N/A of purchased equip cost (B)	-
Contingencies	10% of purchased equip cost (B)	3,988,108
Total Indirect Capital Costs, IC	52% of purchased equip cost (B)	**20,738,163**
Total Capital Investment (TCI) = DC + IC		**90,131,245**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		**89,754,364**
Total Capital Investment (TCI) with Retrofit Factor	0%	**89,754,364**
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	67.53 $/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 100% utilization	147,892
Supervisor	15% of Op., 0.0 , 8760 hr/yr, 100% utilization	22,184
Maintenance		
Maintenance Labor	67.53 $/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 100% utilization	73,946
Maintenance Materials	100% of maintenance labor costs	73,946
Utilities, Supplies, Replacements & Waste Management		
Electricity	0.07 $/kwh, 617.2 kW-hr, 8760 hr/yr, 100% utilization	394,558
Compressed Air	0.48 $/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization	172,552
N/A		-
SW Disposal	63.34 $/ton, 0.1 ton/hr, 8760 hr/yr, 100% utilization	82,486
Lime	183.68 $/ton, 201.1 lb/hr, 8760 hr/yr, 100% utilization	161,806
Filter Bags	228.02 $/bag, 1,356 bags, 8760 hr/yr, 100% utilization	139,692
N/A		
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
Total Annual Direct Operating Costs		**1,269,063**
Indirect Operating Costs		
Overhead	60% of total labor and material costs	190,780
Administration (2% total capital costs)	2% of total capital costs (TCI)	1,795,087
Property tax (1% total capital costs)	1% of total capital costs (TCI)	897,544
Insurance (1% total capital costs)	1% of total capital costs (TCI)	897,544
Capital Recovery	0.0837 for a 20- year equipment life and a 5.5% interest rate	7,650,277
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**11,431,233**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**12,700,296**

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.5 – Table C.5-3: SO_2 Control Spray Dry Absorber (SDA)

Power Station Boiler No. 8

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:	**Filter Bags**		
Equipment Life	3	years	
CRF	0.3707		
Rep part cost per unit	228.02	$/bag	
Amount Required	1356		
Total Rep Parts Cost	346,352	Cost adjusted for freight & sales tax	
Installation Labor	30,529	10 min per bag	EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**376,881**		
Annualized Cost	**139,692**		

Electrical Use

	Flow acfm	D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	341,000	10.00			5,406,760	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total					5,406,760	

Reagents and Other Operating Costs

Lime Use Rate	1.30	lb-mole CaO/lb-mole SO2	201.12 lb/hr Lime
Solid Waste Disposal	1,302	ton/yr GSA unreacted sorbent and reaction byproducts	

Operating Cost Calculations

Utilization Rate	100%	Annual Operating Hours		8,760				
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***		**Annual Cost**	**Comments**
Operating Labor								
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	2,190	$	147,892	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 100% utilization
Supervisor	15%	of Op.			NA	$	22,184	of Op., 0.0 , 8760 hr/yr, 100% utilization
Maintenance								
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	1,095	$	73,946	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 100% utilization
Maint Mtls	100	% of Maintenance Labor			NA	$	73,946	% of Maintenance Labor, 0.0 , 8760 hr/yr, 100% utilization
Utilities, Supplies, Replacements & Waste Management								
Electricity	0.073	$/kwh	617.2	kW-hr	5,406,760	$	394,558	$/kwh, 617.2 kW-hr, 8760 hr/yr, 100% utilization
Compressed Air	0.481	$/kscf	2	scfm/kacfm	358,459	$	172,552	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization
Water	5.129	$/mgal		gpm				$/mgal, 0 gpm, 8760 hr/yr, 100% utilization
SW Disposal	63.34	$/ton	0.15	ton/hr	1,302	$	82,486	$/ton, 0.1 ton/hr, 8760 hr/yr, 100% utilization
Lime	183.68	$/ton	201.1	lb/hr	881	$	161,806	$/ton, 201.1 lb/hr, 8760 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	1,356	bags	N/A	$	139,692	$/bag, 1,356 bags, 8760 hr/yr, 100% utilization

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.5 – Table C.5-4: SO_2 Control Dry Sorbent Injection (DSI)

Power Station Boiler No. 8

Operating Unit: **Power Station Boiler No. 8**

Emission Unit Number			Stack/Vent Number		
Design Capacity	650	MMBtu/hr	Standardized Flow Rate	191,739	scfm @ 32º F
Utilization Rate	100%		Exhaust Temperature	415	Deg F
Annual Operating Hours	8,760	hr/yr	Exhaust Moisture Content	12.8%	
Annual Interest Rate	5.50%		Actual Flow Rate	341,000	acfm
Control Equipment Life	20	yrs	Standardized Flow Rate	205,769	scfm @ 68º F
Plant Elevation	610	ft	Dry Std Flow Rate	175,000	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**6,358,707**
Purchased Equipment Total (B)	22%	of control device cost (A)	**7,757,623**
Installation - Standard Costs	74%	of purchased equip cost (B)	5,740,641
Installation - Site Specific Costs			N/A
Installation Total			5,740,641
Total Direct Capital Cost, DC			13,498,264
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	4,033,964
Total Capital Investment (TCI) = DC + IC			**17,155,347**
Adjusted TCI for Replacement Parts			17,155,347
Total Capital Investment (TCI) with Retrofit Factor			**17,155,347**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	2,081,855
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	2,452,235
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,534,089**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual Ton/Yr**	**Cont Eff %**	**Cont Emis Ton/Yr**	**Reduction Ton/Yr**	**Cont Cost $/Ton Rem**
PM10						
PM2.5						
Total Particulates						
Nitrous Oxides (NOx)						
Sulfur Dioxide (SO2)	148.63	651.02	70%	195.31	455.71	$9,900
Sulfuric Acid Mist (H2SO4)						
Fluorides						
Volatile Organic Compounds (VOC)						
Carbon Monoxide (CO)						
Lead (Pb)						

Notes & Assumptions

1. Baghouse capital cost estimate based on EPA-R05-OAR-2010-0954-0079, ancillary equipment from other Barr Engineering projects
2. Costs scaled up to design airflow using the 6/10 power law
3. Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.5 – Table C.5-4: SO_2 Control Dry Sorbent Injection (DSI)
Power Station Boiler No. 8

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) [1]			**6,358,707**
Purchased Equipment Costs (A) - Injection System + auxiliary equipment, EC			
Instrumentation	10%	Included in vendor estimate	635,871
State Sales Taxes	7.0%	of control device cost (A)	445,110
Freight	5%	of control device cost (A)	317,935
Purchased Equipment Total (B)	22%		**7,757,623**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	310,305
Handling & erection	50%	of purchased equip cost (B)	3,878,811
Electrical	8%	of purchased equip cost (B)	620,610
Piping	1%	of purchased equip cost (B)	77,576
Insulation	7%	of purchased equip cost (B)	543,034
Painting	4%	Included in vendor estimate	310,305
Installation Subtotal Standard Expenses	74%		**5,740,641**
Other Specific Costs (see summary)			
Site Preparation, as required	N/A	Site Specific	
Buildings, as required	N/A	Site Specific	
Lost Production for Tie-In	N/A	Site Specific	
Total Site Specific Costs			N/A
Installation Total			**5,740,641**
Total Direct Capital Cost, DC			**13,498,264**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	775,762
Construction & field expenses	20%	of purchased equip cost (B)	1,551,525
Contractor fees	10%	of purchased equip cost (B)	775,762
Start-up	1%	of purchased equip cost (B)	77,576
Performance test	1%	of purchased equip cost (B)	77,576
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	775,762
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**4,033,964**
Total Capital Investment (TCI) = DC + IC			**17,532,228**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**17,155,347**
Total Capital Investment (TCI) with Retrofit Factor	0%		**17,155,347**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	67.53	$/Hr	147,892
Supervisor	0.15	of Op Labor	22,184
Maintenance			
Maintenance Labor	67.53	$/Hr	73,946
Maintenance Materials	100	% of Maintenance Labor	73,946
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.07	$/kwh, 370.3 kW-hr, 8760 hr/yr, 100% utilization	236,735
N/A			-
Compressed Air	0.48	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization	172,552
N/A			-
Solid Waste Disposal	63.34	$/ton, 0.3 ton/hr, 8760 hr/yr, 100% utilization	184,045
Trona	285.00	$/ton, 825.8 lb/hr, 8760 hr/yr, 100% utilization	1,030,862
Filter Bags	228.02	$/bag, 1,356 bags, 8760 hr/yr, 100% utilization	139,692
N/A			-
N/A			-
N/A			-
N/A			-
Total Annual Direct Operating Costs			**2,081,855**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	190,780
Administration (2% total capital costs)	2%	of total capital costs (TCI)	343,107
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	171,553
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	171,553
Capital Recovery	0.0837	for a 20-year equipment life and a 5.5% interest rate	1,435,548
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery costs	**2,452,235**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,534,089**

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.5 – Table C.5-4: SO_2 Control Dry Sorbent Injection (DSI)

Power Station Boiler No. 8

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:	**Filter Bags**	
Equipment Life	3	years
CRF	0.3707	
Rep part cost per unit	228.02	$/bag
Amount Required	1356	Bags
Total Rep Parts Cost	346,352	Cost adjusted for freight, sales tax, and bag disposal
Installation Labor	30,529	20 min per bag
Total Installed Cost	**376,881**	
Annualized Cost	**139,692**	

Electrical Use

	Flow acfm	D P in H2O	kWhr/yr	
Blower	341,000	6.00	3,244,056	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total			3,244,056	

Reagent Use & Other Operating Costs

Trona use - 1.5 NSR	148.63	lb/hr SO2	825.81	lb/hr Trona
Solid Waste Disposal	2,906	ton/yr DSI unreacted sorbent and reaction byproducts		

Operating Cost Calculations

Utilization Rate	100%	Annual Operating Hours		8,760				
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***		**Annual Cost**	**Comments**
Operating Labor								
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	2,190	$	147,892	$/Hr, 2.0 hr/8 hr shift, 2,190 hr/yr
Supervisor	15%	of Op Labor			NA	$	22,184	% of Operator Costs
Maintenance								
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	1,095	$	73,946	$/Hr, 1.0 hr/8 hr shift, 1,095 hr/yr
Maint Mtls	100%	of Maintenance Labor			NA	$	73,946	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management								
Electricity	0.073	$/kwh	370.3	kW-hr	3,244,056	$	236,735	$/kwh, 370.3 kW-hr, 8760 hr/yr, 100% utilization
Water			N/A	gpm				
Compressed Air	0.481	$/kscf	2.0	scfm/kacfm	358,459	$	172,552	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization
Cooling Water			N/A	gpm				
Solid Waste Disposal	63.34	$/ton	0.3	ton/hr	2,906	$	184,045	$/ton, 0.3 ton/hr, 8760 hr/yr, 100% utilization
Trona	285.00	$/ton	825.8	lb/hr	3,617	$	1,030,862	$/ton, 825.8 lb/hr, 8760 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	1,356	bags	N/A	$	139,692	$/bag, 1,356 bags, 8760 hr/yr, 100% utilization

Appendix C.6

Power Station Boiler No. 9

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.6 – Table C.6-1: Cost Summary
Power Station Boiler No. 9

SO_2 Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Total Annualized Cost $/yr	Pollution Control Cost $/ton
Spray Dry Absorber (SDA)	90%	52.4	471.8	$90,131,245	$12,633,930	$26,781
Dry Sorbent Injection (DSI)	70%	157.3	366.9	$16,690,046	$4,223,662	$11,500

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.6 – Table C.6-2: Summary of Utility, Chemical and Supply Costs
Power Station Boiler No. 9

Operating Unit:	Power Station Boiler No. 9	**Study Year**	2020
Emission Unit Number			
Stack/Vent Number			

Item	2020 Unit Cost	Units	Cost	Year	Data Source	Notes
Operating Labor	68	$/hr	60	2016	EPA SCR Control Cost Manual Spreadsheet	
Maintenance Labor	68	$/hr				Assumed to be equivalent to operating labor
Installation Labor	68	$/hr				Assumed to be equivalent to operating labor
Electricity	0.07	$/kwh			2016-2019 EIA Average prices for the industrial sector in Indiana	
Natural Gas	6.15	$/kscf			2014-2018 EIA Average prices for the Industrial sector in Indiana (latest available 8/20/2020)	
Compressed Air	0.48	$/kscf	0.38	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Chemicals & Supplies						
Lime	183.68	$/ton	145.00	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Trona	285.00	$/ton		2020	Reagent cost for trona from another Barr Engineering Co. Project.	
Fabric Filter Bags	228.02	$/bag	180	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Other						
Sales Tax	7%			2020	Indiana sales tax rate	
Interest Rate	5.50%			2016	EPA SCR Control Cost Manual Spreadsheet	
Solid Waste Disposal	63.34	$/ton	50	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Contingencies	10%	of purchased equip cost (B)			EPA Cost Control Cost Manual Chapter 2	Suggested contingency range of 5% to 15% of total capital investment
Markup on capital investment (retrofit factor)	0%				EPA Cost Control Cost Manual Chapter 2	
Operating Information						
Annual Op. Hrs	8,760	Hours			Emission Inventory Data	
Utilization Rate	100%				Assumed	
Design Capacity	650.0	MMBTU/hr			Boiler Design Capacity	
Equipment Life	20	yrs			Assumed	
Temperature	451	Deg F			Performance test data	
Moisture Content	17.0%				Performance test data	
Actual Flow Rate	333,000	acfm			Performance test data	
Standardized Flow Rate	193,001	scfm @ 68º F	179,842	scfm @ 32º F	Calculated Value	
Dry Std Flow Rate	157,000	dscfm @ 68º F			Performance test data	
Plant Elevation	610	Feet above sea level				Plant elevation
	Baseline Emissions		**lb/hr**	**ton/year**		
Pollutant	**Lb/Hr**	**Ton/Year**	**ppmv**	**ppmv**	**lb/mmbtu**	
Nitrous Oxides (NOx)	42.0	184.0	37	37.3		Emission inventory data
Sulfur Dioxides (SO2)	119.7	524.2	76	76.4		Emission inventory data
SDA - SO_2 Control Efficiency	90%				EPA fact sheet for flue gas desulfurization (new installations) https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf	
DSI - SO_2 Control Efficiency	70%				Control efficiency is based on trona as injected reagent.	

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.6 – Table C.6-3: SO_2 Control Spray Dry Absorber (SDA)

Power Station Boiler No. 9

Operating Unit: **Power Station Boiler No. 9**

Emission Unit Number	0		Stack/Vent Number	0	
Design Capacity	650	MMBtu/hr	Standardized Flow Rate	179,842	scfm @ 32º F
Utilization Rate	100%		Temperature	451	Deg F
Annual Operating Hours	8,760	Hours	Moisture Content	17.0%	
Annual Interest Rate	5.5%		Actual Flow Rate	333,000	acfm
Equipment Life	20	yrs	Standardized Flow Rate	193,001	scfm @ 68º F
			Dry Std Flow Rate	157,000	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment (A)								**32,689,411**
Purchased Equipment Total (B)	22%	of control device cost (A)						**39,881,082**
Installation - Standard Costs	74%	of purchased equip cost (B)						29,512,001
Installation - Site Specific Costs								NA
Installation Total								29,512,001
Total Direct Capital Cost, DC								69,393,083
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)						20,738,163
Total Capital Investment (TCI) = DC + IC								**90,131,245**
Adjusted TCI for Replacment Parts								**89,763,206**
TCI with Retrofit Factor								**89,763,206**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						1,204,881
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						11,429,049
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**12,633,930**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc.**	**Conc. Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10						0.0	-	NA
PM2.5						0.0	-	NA
Total Particulates						0.0	-	NA
Nitrous Oxides (NOx)						0.0	-	NA
Sulfur Dioxide (SO_2)		524.2	90%			52.4	471.8	26,781
Sulfuric Acid Mist						0.00	-	NA
Fluorides						0.0	-	NA
Volatile Organic Compounds (VOC)						0.0	-	NA
Carbon Monoxide (CO)						0.0	-	NA
Lead (Pb)						0.00	-	NA

Notes & Assumptions

1 Capital cost estimate based on mid-range of EPA spray dry fact sheet $/(MMBtu/hr): https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf
2 Costs scaled up to design airflow using the 6/10 power law
3 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.6 – Table C.6-3: SO_2 Control Spray Dry Absorber (SDA)
Power Station Boiler No. 9

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (A) [1]		**32,689,411**
Purchased Equipment Costs (A) - Absorber + packing + auxiliary equipment, EC		
Instrumentation	10% of control device cost (A)	3,268,941
State Sales Taxes	7.0% of control device cost (A)	2,288,259
Freight	5% of control device cost (A)	1,634,471
Purchased Equipment Total (B)	22%	**39,881,082**
Installation		
Foundations & supports	4% of purchased equip cost (B)	1,595,243
Handling & erection	50% of purchased equip cost (B)	19,940,541
Electrical	8% of purchased equip cost (B)	3,190,487
Piping	1% of purchased equip cost (B)	398,811
Insulation	7% of purchased equip cost (B)	2,791,676
Painting	4% of purchased equip cost (B)	1,595,243
Installation Subtotal Standard Expenses	74%	**29,512,001**
Other Specific Costs (see summary)		
Site Preparation, as required	N/A Site Specific	-
Buildings, as required	N/A Site Specific	-
Site Specific - Other	N/A Site Specific	-
Total Site Specific Costs		NA
Installation Total		**29,512,001**
Total Direct Capital Cost, DC		**69,393,083**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	3,988,108
Construction & field expenses	20% of purchased equip cost (B)	7,976,216
Contractor fees	10% of purchased equip cost (B)	3,988,108
Start-up	1% of purchased equip cost (B)	398,811
Performance test	1% of purchased equip cost (B)	398,811
Model Studies	N/A of purchased equip cost (B)	-
Contingencies	10% of purchased equip cost (B)	3,988,108
Total Indirect Capital Costs, IC	52% of purchased equip cost (B)	**20,738,163**
Total Capital Investment (TCI) = DC + IC		**90,131,245**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		**89,763,206**
Total Capital Investment (TCI) with Retrofit Factor	0%	**89,763,206**
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	67.53 $/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 100% utilization	147,892
Supervisor	15% of Op., 0.0 , 8760 hr/yr, 100% utilization	22,184
Maintenance		
Maintenance Labor	67.53 $/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 100% utilization	73,946
Maintenance Materials	100% of maintenance labor costs	73,946
Utilities, Supplies, Replacements & Waste Management		
Electricity	0.07 $/kwh, 602.7 kW-hr, 8760 hr/yr, 100% utilization	385,302
Compressed Air	0.48 $/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization	168,504
N/A		-
SW Disposal	63.34 $/ton, 0.1 ton/hr, 8760 hr/yr, 100% utilization	66,414
Lime	183.68 $/ton, 161.9 lb/hr, 8760 hr/yr, 100% utilization	130,279
Filter Bags	228.02 $/bag, 1,324 bags, 8760 hr/yr, 100% utilization	136,415
N/A		
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
Total Annual Direct Operating Costs		**1,204,881**
Indirect Operating Costs		
Overhead	60% of total labor and material costs	190,780
Administration (2% total capital costs)	2% of total capital costs (TCI)	1,795,264
Property tax (1% total capital costs)	1% of total capital costs (TCI)	897,632
Insurance (1% total capital costs)	1% of total capital costs (TCI)	897,632
Capital Recovery	0.0837 for a 20- year equipment life and a 5.5% interest rate	7,647,740
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**11,429,049**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**12,633,930**

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.6 – Table C.6-3: SO_2 Control Spray Dry Absorber (SDA)

Power Station Boiler No. 9

Capital Recovery Factors

Primary Installation	
Interest Rate	5.50%
Equipment Life	20 years
CRF	0.0837

Replacement Parts & Equipment:	**Filter Bags**	
Equipment Life	3 years	
CRF	0.3707	
Rep part cost per unit	228.02 $/bag	
Amount Required	1324	
Total Rep Parts Cost	338,227 Cost adjusted for freight & sales tax	
Installation Labor	29,812 10 min per bag	EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**368,039**	
Annualized Cost	**136,415**	

Electrical Use

	Flow acfm	D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	333,000	10.00			5,279,915	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total					5,279,915	

Reagents and Other Operating Costs

Lime Use Rate	1.30 lb-mole CaO/lb-mole SO2	161.93 lb/hr Lime
Solid Waste Disposal	1,049 ton/yr GSA unreacted sorbent and reaction byproducts	

Operating Cost Calculations

Utilization Rate 100% | Annual Operating Hours 8,760

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	2,190	$ 147,892	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 100% utilization
Supervisor	15%	of Op.			NA	$ 22,184	of Op., 0.0 , 8760 hr/yr, 100% utilization
Maintenance							
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	1,095	$ 73,946	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 100% utilization
Maint Mtls	100	% of Maintenance Labor			NA	$ 73,946	% of Maintenance Labor, 0.0 , 8760 hr/yr, 100% utilization
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.073	$/kwh	602.7	kW-hr	5,279,915	$ 385,302	$/kwh, 602.7 kW-hr, 8760 hr/yr, 100% utilization
Compressed Air	0.481	$/kscf	2	scfm/kacfm	350,050	$ 168,504	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization
Water	5.129	$/mgal		gpm			$/mgal, 0 gpm, 8760 hr/yr, 100% utilization
SW Disposal	63.34	$/ton	0.12	ton/hr	1,049	$ 66,414	$/ton, 0.1 ton/hr, 8760 hr/yr, 100% utilization
Lime	183.68	$/ton	161.9	lb/hr	709	$ 130,279	$/ton, 161.9 lb/hr, 8760 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	1,324	bags	N/A	$ 136,415	$/bag, 1,324 bags, 8760 hr/yr, 100% utilization

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.6 – Table C.6-4: SO_2 Control Dry Sorbent Injection (DSI)

Power Station Boiler No. 9

Operating Unit: **Power Station Boiler No. 9**

Emission Unit Number			Stack/Vent Number		
Design Capacity	650	MMBtu/hr	Standardized Flow Rate	179,842	scfm @ 32º F
Utilization Rate	100%		Exhaust Temperature	451	Deg F
Annual Operating Hours	8,760	hr/yr	Exhaust Moisture Content	17.0%	
Annual Interest Rate	5.50%		Actual Flow Rate	333,000	acfm
Control Equipment Life	20	yrs	Standardized Flow Rate	193,001	scfm @ 68º F
Plant Elevation	610	ft	Dry Std Flow Rate	157,000	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs						
Direct Capital Costs						
Purchased Equipment (A)						**6,186,742**
Purchased Equipment Total (B)	22%	of control device cost (A)				**7,547,825**
Installation - Standard Costs	74%	of purchased equip cost (B)				5,585,391
Installation - Site Specific Costs						N/A
Installation Total						5,585,391
Total Direct Capital Cost, DC						13,133,216
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)				3,924,869
Total Capital Investment (TCI) = DC + IC						**16,690,046**
Adjusted TCI for Replacement Parts						16,690,046
Total Capital Investment (TCI) with Retrofit Factor						**16,690,046**
Operating Costs						
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.				1,832,253
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost				2,391,409
Total Annual Cost (Annualized Capital Cost + Operating Cost)						**4,223,662**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual Ton/Yr	Cont Eff %	Cont Emis Ton/Yr	Reduction Ton/Yr	Cont Cost $/Ton Rem
PM10						
PM2.5						
Total Particulates						
Nitrous Oxides (NOx)						
Sulfur Dioxide (SO2)	119.67	524.17	70%	157.25	366.92	$11,500
Sulfuric Acid Mist (H2SO4)						
Fluorides						
Volatile Organic Compounds (VOC)						
Carbon Monoxide (CO)						
Lead (Pb)						

Notes & Assumptions

1. Baghouse capital cost estimate based on EPA-R05-OAR-2010-0954-0079, ancillary equipment from other Barr Engineering projects
2. Costs scaled up to design airflow using the 6/10 power law
3. Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.6 – Table C.6-4: SO_2 Control Dry Sorbent Injection (DSI)

Power Station Boiler No. 9

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) [1]			**6,186,742**
Purchased Equipment Costs (A) - Injection System + auxiliary equipment, EC			
Instrumentation	10%	Included in vendor estimate	618,674
State Sales Taxes	7.0%	of control device cost (A)	433,072
Freight	5%	of control device cost (A)	309,337
Purchased Equipment Total (B)	22%		**7,547,825**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	301,913
Handling & erection	50%	of purchased equip cost (B)	3,773,913
Electrical	8%	of purchased equip cost (B)	603,826
Piping	1%	of purchased equip cost (B)	75,478
Insulation	7%	of purchased equip cost (B)	528,348
Painting	4%	Included in vendor estimate	301,913
Installation Subtotal Standard Expenses	74%		**5,585,391**
Other Specific Costs (see summary)			
Site Preparation, as required	N/A	Site Specific	
Buildings, as required	N/A	Site Specific	
Lost Production for Tie-In	N/A	Site Specific	
Total Site Specific Costs			N/A
Installation Total			**5,585,391**
Total Direct Capital Cost, DC			**13,133,216**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	754,783
Construction & field expenses	20%	of purchased equip cost (B)	1,509,565
Contractor fees	10%	of purchased equip cost (B)	754,783
Start-up	1%	of purchased equip cost (B)	75,478
Performance test	1%	of purchased equip cost (B)	75,478
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	754,783
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**3,924,869**
Total Capital Investment (TCI) = DC + IC			**17,058,085**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**16,690,046**
Total Capital Investment (TCI) with Retrofit Factor	0%		**16,690,046**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	67.53	$/Hr	147,892
Supervisor	0.15	of Op Labor	22,184
Maintenance			
Maintenance Labor	67.53	$/Hr	73,946
Maintenance Materials	100	% of Maintenance Labor	73,946
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.07	$/kwh, 361.6 kW-hr, 8760 hr/yr, 100% utilization	231,181
N/A			-
Compressed Air	0.48	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization	168,504
N/A			-
Solid Waste Disposal	63.34	$/ton, 0.3 ton/hr, 8760 hr/yr, 100% utilization	148,184
Trona	285.00	$/ton, 664.9 lb/hr, 8760 hr/yr, 100% utilization	830,001
Filter Bags	228.02	$/bag, 1,324 bags, 8760 hr/yr, 100% utilization	136,415
N/A			-
N/A			-
N/A			-
N/A			-
Total Annual Direct Operating Costs			**1,832,253**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	190,780
Administration (2% total capital costs)	2%	of total capital costs (TCI)	333,801
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	166,900
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	166,900
Capital Recovery	0.0837	for a 20-year equipment life and a 5.5% interest rate	1,396,612
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery costs	**2,391,409**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,223,662**

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.6 – Table C.6-4: SO_2 Control Dry Sorbent Injection (DSI)

Power Station Boiler No. 9

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:	**Filter Bags**	
Equipment Life	3	years
CRF	0.3707	
Rep part cost per unit	228.02	$/bag
Amount Required	1324	Bags
Total Rep Parts Cost	338,227	Cost adjusted for freight, sales tax, and bag disposal
Installation Labor	29,812	20 min per bag
Total Installed Cost	**368,039**	
Annualized Cost	**136,415**	

Electrical Use

	Flow acfm	D P in H2O	kWhr/yr	
Blower	333,000	6.00	3,167,949	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total			3,167,949	

Reagent Use & Other Operating Costs

Trona use - 1.5 NSR	119.67	lb/hr SO2	664.90	lb/hr Trona
Solid Waste Disposal	2,340	ton/yr DSI unreacted sorbent and reaction byproducts		

Operating Cost Calculations

Utilization Rate	100%	Annual Operating Hours		8,760			
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	2,190	$ 147,892	$/Hr, 2.0 hr/8 hr shift, 2,190 hr/yr
Supervisor	15%	of Op Labor			NA	$ 22,184	% of Operator Costs
Maintenance							
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	1,095	$ 73,946	$/Hr, 1.0 hr/8 hr shift, 1,095 hr/yr
Maint Mtls	100%	of Maintenance Labor			NA	$ 73,946	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.073	$/kwh	361.6	kW-hr	3,167,949	$ 231,181	$/kwh, 361.6 kW-hr, 8760 hr/yr, 100% utilization
Water			N/A	gpm			
Compressed Air	0.481	$/kscf	2.0	scfm/kacfm	350,050	$ 168,504	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization
Cooling Water			N/A	gpm			
Solid Waste Disposal	63.34	$/ton	0.3	ton/hr	2,340	$ 148,184	$/ton, 0.3 ton/hr, 8760 hr/yr, 100% utilization
Trona	285.00	$/ton	664.9	lb/hr	2,912	$ 830,001	$/ton, 664.9 lb/hr, 8760 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	1,324	bags	N/A	$ 136,415	$/bag, 1,324 bags, 8760 hr/yr, 100% utilization

Appendix C.7

Power Station Boiler No. 10

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.7 – Table C.7-1: Cost Summary
Power Station Boiler No. 10

SO_2 Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Total Annualized Cost $/yr	Pollution Control Cost $/ton
Spray Dry Absorber (SDA)	90%	33.4	300.2	$90,131,245	$12,599,932	$41,972
Dry Sorbent Injection (DSI)	70%	100.1	233.5	$16,669,213	$3,897,671	$16,700

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.7 – Table C.7-2: Summary of Utility, Chemical and Supply Costs
Power Station Boiler No. 10

Operating Unit:	Power Station Boiler No. 10	**Study Year**	2020
Emission Unit Number			
Stack/Vent Number			

Item	2020 Unit Cost	Units	Cost	Year	Data Source	Notes
Operating Labor	68	$/hr	60	2016	EPA SCR Control Cost Manual Spreadsheet	
Maintenance Labor	68	$/hr				Assumed to be equivalent to operating labor
Installation Labor	68	$/hr				Assumed to be equivalent to operating labor
Electricity	0.07	$/kwh			2016-2019 EIA Average prices for the industrial sector in Indiana	
Natural Gas	6.15	$/kscf			2014-2018 EIA Average prices for the Industrial sector in Indiana (latest available 8/20/2020)	
Compressed Air	0.48	$/kscf	0.38	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Chemicals & Supplies						
Lime	183.68	$/ton	145.00	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Trona	285.00	$/ton		2020	Reagent cost for trona from another Barr Engineering Co. Project.	
Fabric Filter Bags	228.02	$/bag	180	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Other						
Sales Tax	7%			2020	Indiana sales tax rate	
Interest Rate	5.50%			2016	EPA SCR Control Cost Manual Spreadsheet	
Solid Waste Disposal	63.34	$/ton	50	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Contingencies	10%	of purchased equip cost (B)			EPA Cost Control Cost Manual Chapter 2	Suggested contingency range of 5% to 15% of total capital investment
Markup on capital investment (retrofit factor)	0%				EPA Cost Control Cost Manual Chapter 2	
Operating Information						
Annual Op. Hrs	8,760	Hours			Emission Inventory Data	
Utilization Rate	100%				Assumed	
Design Capacity	650.0	MMBTU/hr			Boiler Design Capacity	
Equipment Life	20	yrs			Assumed	
Temperature	432	Deg F			Performance test data	
Moisture Content	13.7%				Performance test data	
Actual Flow Rate	349,000	acfm			Performance test data	
Standardized Flow Rate	206,583	scfm @ 68º F	192,498	scfm @ 32º F	Calculated Value	
Dry Std Flow Rate	174,000	dscfm @ 68º F			Performance test data	
Plant Elevation	610	Feet above sea level				Plant elevation
	Baseline Emissions		**lb/hr**	**ton/year**		
Pollutant	**Lb/Hr**	**Ton/Year**	**ppmv**	**ppmv**	**lb/mmbtu**	
Nitrous Oxides (NOx)	38.8	170.0	31	31.1		Emission inventory data
Sulfur Dioxides (SO2)	76.2	333.6	44	43.8		Emission inventory data
SDA - SO_2 Control Efficiency	90%				EPA fact sheet for flue gas desulfurization (new installations) https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf	
DSI - SO_2 Control Efficiency	70%				Control efficiency is based on trona as injected reagent.	

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.7 – Table C.7-3: SO_2 Control Spray Dry Absorber (SDA)

Power Station Boiler No. 10

Operating Unit: **Power Station Boiler No. 10**

Emission Unit Number	0		Stack/Vent Number	0	
Design Capacity	650	MMBtu/hr	Standardized Flow Rate	192,498	scfm @ 32º F
Utilization Rate	100%		Temperature	432	Deg F
Annual Operating Hours	8,760	Hours	Moisture Content	13.7%	
Annual Interest Rate	5.5%		Actual Flow Rate	349,000	acfm
Equipment Life	20	yrs	Standardized Flow Rate	206,583	scfm @ 68º F
			Dry Std Flow Rate	174,000	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**32,689,411**
Purchased Equipment Total (B)	22%	of control device cost (A)	**39,881,082**
Installation - Standard Costs	74%	of purchased equip cost (B)	29,512,001
Installation - Site Specific Costs			NA
Installation Total			29,512,001
Total Direct Capital Cost, DC			69,393,083
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	20,738,163
Total Capital Investment (TCI) = DC + IC			**90,131,245**
Adjusted TCI for Replacment Parts			**89,745,523**
TCI with Retrofit Factor			**89,745,523**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	1,166,516
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	11,433,416
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**12,599,932**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual T/Yr	Cont Eff %	Exit Conc.	Conc. Units	Cont Emis T/yr	Reduction T/yr	Cont Cost $/Ton Rem
PM10						0.0	-	NA
PM2.5						0.0	-	NA
Total Particulates						0.0	-	NA
Nitrous Oxides (NOx)						0.0	-	NA
Sulfur Dioxide (SO_2)		333.6	90%			33.4	300.2	41,972
Sulfuric Acid Mist						0.00	-	NA
Fluorides						0.0	-	NA
Volatile Organic Compounds (VOC)						0.0	-	NA
Carbon Monoxide (CO)						0.0	-	NA
Lead (Pb)						0.00	-	NA

Notes & Assumptions

1. Capital cost estimate based on mid-range of EPA spray dry fact sheet $/(MMBtu/hr): https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf
2. Costs scaled up to design airflow using the 6/10 power law
3. Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.7 – Table C.7-3: SO_2 Control Spray Dry Absorber (SDA)

Power Station Boiler No. 10

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (A) [1]		**32,689,411**
Purchased Equipment Costs (A) - Absorber + packing + auxiliary equipment, EC		
Instrumentation	10% of control device cost (A)	3,268,941
State Sales Taxes	7.0% of control device cost (A)	2,288,259
Freight	5% of control device cost (A)	1,634,471
Purchased Equipment Total (B)	22%	**39,881,082**
Installation		
Foundations & supports	4% of purchased equip cost (B)	1,595,243
Handling & erection	50% of purchased equip cost (B)	19,940,541
Electrical	8% of purchased equip cost (B)	3,190,487
Piping	1% of purchased equip cost (B)	398,811
Insulation	7% of purchased equip cost (B)	2,791,676
Painting	4% of purchased equip cost (B)	1,595,243
Installation Subtotal Standard Expenses	74%	**29,512,001**
Other Specific Costs (see summary)		
Site Preparation, as required	N/A Site Specific	-
Buildings, as required	N/A Site Specific	-
Site Specific - Other	N/A Site Specific	-
Total Site Specific Costs		NA
Installation Total		**29,512,001**
Total Direct Capital Cost, DC		**69,393,083**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	3,988,108
Construction & field expenses	20% of purchased equip cost (B)	7,976,216
Contractor fees	10% of purchased equip cost (B)	3,988,108
Start-up	1% of purchased equip cost (B)	398,811
Performance test	1% of purchased equip cost (B)	398,811
Model Studies	N/A of purchased equip cost (B)	-
Contingencies	10% of purchased equip cost (B)	3,988,108
Total Indirect Capital Costs, IC	52% of purchased equip cost (B)	**20,738,163**
Total Capital Investment (TCI) = DC + IC		**90,131,245**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		**89,745,523**
Total Capital Investment (TCI) with Retrofit Factor	0%	**89,745,523**
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	67.53 $/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 100% utilization	147,892
Supervisor	15% of Op., 0.0 , 8760 hr/yr, 100% utilization	22,184
Maintenance		
Maintenance Labor	67.53 $/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 100% utilization	73,946
Maintenance Materials	100% of maintenance labor costs	73,946
Utilities, Supplies, Replacements & Waste Management		
Electricity	0.07 $/kwh, 631.7 kW-hr, 8760 hr/yr, 100% utilization	403,815
Compressed Air	0.48 $/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization	176,601
N/A		-
SW Disposal	63.34 $/ton, 0.1 ton/hr, 8760 hr/yr, 100% utilization	42,262
Lime	183.68 $/ton, 103.0 lb/hr, 8760 hr/yr, 100% utilization	82,901
Filter Bags	228.02 $/bag, 1,388 bags, 8760 hr/yr, 100% utilization	142,970
N/A		
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
Total Annual Direct Operating Costs		**1,166,516**
Indirect Operating Costs		
Overhead	60% of total labor and material costs	190,780
Administration (2% total capital costs)	2% of total capital costs (TCI)	1,794,910
Property tax (1% total capital costs)	1% of total capital costs (TCI)	897,455
Insurance (1% total capital costs)	1% of total capital costs (TCI)	897,455
Capital Recovery	0.0837 for a 20- year equipment life and a 5.5% interest rate	7,652,815
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**11,433,416**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**12,599,932**

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.7 – Table C.7-3: SO_2 Control Spray Dry Absorber (SDA)
Power Station Boiler No. 10

Capital Recovery Factors

Primary Installation	
Interest Rate	5.50%
Equipment Life	20 years
CRF	0.0837

Replacement Parts & Equipment:	**Filter Bags**	
Equipment Life	3 years	
CRF	0.3707	
Rep part cost per unit	228.02 $/bag	
Amount Required	1388	
Total Rep Parts Cost	354,478 Cost adjusted for freight & sales tax	
Installation Labor	31,245 10 min per bag	EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**385,723**	
Annualized Cost	**142,970**	

Electrical Use

	Flow acfm	D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	349,000	10.00			5,533,604	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total					5,533,604	

Reagents and Other Operating Costs

Lime Use Rate	1.30 lb-mole CaO/lb-mole SO2	103.04 lb/hr Lime
Solid Waste Disposal	667 ton/yr GSA unreacted sorbent and reaction byproducts	

Operating Cost Calculations

Utilization Rate 100% | Annual Operating Hours 8,760

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	2,190	$ 147,892	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 100% utilization
Supervisor	15%	of Op.			NA	$ 22,184	of Op., 0.0 , 8760 hr/yr, 100% utilization
Maintenance							
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	1,095	$ 73,946	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 100% utilization
Maint Mtls	100	% of Maintenance Labor			NA	$ 73,946	% of Maintenance Labor, 0.0 , 8760 hr/yr, 100% utilization
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.073	$/kwh	631.7	kW-hr	5,533,604	$ 403,815	$/kwh, 631.7 kW-hr, 8760 hr/yr, 100% utilization
Compressed Air	0.481	$/kscf	2	scfm/kacfm	366,869	$ 176,601	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization
Water	5.129	$/mgal		gpm			$/mgal, 0 gpm, 8760 hr/yr, 100% utilization
SW Disposal	63.34	$/ton	0.08	ton/hr	667	$ 42,262	$/ton, 0.1 ton/hr, 8760 hr/yr, 100% utilization
Lime	183.68	$/ton	103.0	lb/hr	451	$ 82,901	$/ton, 103.0 lb/hr, 8760 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	1,388	bags	N/A	$ 142,970	$/bag, 1,388 bags, 8760 hr/yr, 100% utilization

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.7 – Table C.7-4: SO_2 Control Dry Sorbent Injection (DSI)
Power Station Boiler No. 10

Operating Unit: **Power Station Boiler No. 10**

Emission Unit Number			Stack/Vent Number		
Design Capacity	650	MMBtu/hr	Standardized Flow Rate	192,498	scfm @ 32º F
Utilization Rate	100%		Exhaust Temperature	432	Deg F
Annual Operating Hours	8,760	hr/yr	Exhaust Moisture Content	13.7%	
Annual Interest Rate	5.50%		Actual Flow Rate	349,000	acfm
Control Equipment Life	20	yrs	Standardized Flow Rate	206,583	scfm @ 68º F
Plant Elevation	610	ft	Dry Std Flow Rate	174,000	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs						
Direct Capital Costs						
Purchased Equipment (A)						**6,185,600**
Purchased Equipment Total (B)	22%	of control device cost (A)				**7,546,432**
Installation - Standard Costs	74%	of purchased equip cost (B)				5,584,359
Installation - Site Specific Costs						N/A
Installation Total						5,584,359
Total Direct Capital Cost, DC						13,130,791
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)				3,924,144
Total Capital Investment (TCI) = DC + IC						**16,669,213**
Adjusted TCI for Replacement Parts						16,669,213
Total Capital Investment (TCI) with Retrofit Factor						**16,669,213**
Operating Costs						
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.				1,502,284
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost				2,395,387
Total Annual Cost (Annualized Capital Cost + Operating Cost)						**3,897,671**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual Ton/Yr	Cont Eff %	Cont Emis Ton/Yr	Reduction Ton/Yr	Cont Cost $/Ton Rem
PM10						
PM2.5						
Total Particulates						
Nitrous Oxides (NOx)						
Sulfur Dioxide (SO2)	76.15	333.55	70%	100.07	233.49	$16,700
Sulfuric Acid Mist (H2SO4)						
Fluorides						
Volatile Organic Compounds (VOC)						
Carbon Monoxide (CO)						
Lead (Pb)						

Notes & Assumptions

1 Baghouse capital cost estimate based on EPA-R05-OAR-2010-0954-0079, ancillary equipment from other Barr Engineering projects
2 Costs scaled up to design airflow using the 6/10 power law
3 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.7 – Table C.7-4: SO_2 Control Dry Sorbent Injection (DSI)
Power Station Boiler No. 10

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) [1]			**6,185,600**
Purchased Equipment Costs (A) - Injection System + auxiliary equipment, EC			
Instrumentation	10%	Included in vendor estimate	618,560
State Sales Taxes	7.0%	of control device cost (A)	432,992
Freight	5%	of control device cost (A)	309,280
Purchased Equipment Total (B)	22%		**7,546,432**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	301,857
Handling & erection	50%	of purchased equip cost (B)	3,773,216
Electrical	8%	of purchased equip cost (B)	603,715
Piping	1%	of purchased equip cost (B)	75,464
Insulation	7%	of purchased equip cost (B)	528,250
Painting	4%	Included in vendor estimate	301,857
Installation Subtotal Standard Expenses	74%		**5,584,359**
Other Specific Costs (see summary)			
Site Preparation, as required	N/A	Site Specific	
Buildings, as required	N/A	Site Specific	
Lost Production for Tie-In	N/A	Site Specific	
Total Site Specific Costs			N/A
Installation Total			**5,584,359**
Total Direct Capital Cost, DC			13,130,791
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	754,643
Construction & field expenses	20%	of purchased equip cost (B)	1,509,286
Contractor fees	10%	of purchased equip cost (B)	754,643
Start-up	1%	of purchased equip cost (B)	75,464
Performance test	1%	of purchased equip cost (B)	75,464
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	754,643
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**3,924,144**
Total Capital Investment (TCI) = DC + IC			**17,054,936**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**16,669,213**
Total Capital Investment (TCI) with Retrofit Factor	0%		**16,669,213**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	67.53	$/Hr	147,892
Supervisor	0.15	of Op Labor	22,184
Maintenance			
Maintenance Labor	67.53	$/Hr	73,946
Maintenance Materials	100	% of Maintenance Labor	73,946
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.07	$/kwh, 379.0 kW-hr, 8760 hr/yr, 100% utilization	242,289
N/A			-
Compressed Air	0.48	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization	176,601
N/A			-
Solid Waste Disposal	63.34	$/ton, 0.2 ton/hr, 8760 hr/yr, 100% utilization	94,296
Trona	285.00	$/ton, 423.1 lb/hr, 8760 hr/yr, 100% utilization	528,162
Filter Bags	228.02	$/bag, 1,388 bags, 8760 hr/yr, 100% utilization	142,970
N/A			-
N/A			-
N/A			-
N/A			-
Total Annual Direct Operating Costs			**1,502,284**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	190,780
Administration (2% total capital costs)	2%	of total capital costs (TCI)	333,384
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	166,692
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	166,692
Capital Recovery	0.0837	for a 20-year equipment life and a 5.5% interest rate	1,394,869
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery costs	**2,395,387**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**3,897,671**

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.7 – Table C.7-4: SO_2 Control Dry Sorbent Injection (DSI)
Power Station Boiler No. 10

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:	**Filter Bags**	
Equipment Life	3	years
CRF	0.3707	
Rep part cost per unit	228.02	$/bag
Amount Required	1388	Bags
Total Rep Parts Cost	354,478	Cost adjusted for freight, sales tax, and bag disposal
Installation Labor	31,245	20 min per bag
Total Installed Cost	**385,723**	
Annualized Cost	**142,970**	

Electrical Use

	Flow acfm	D P in H2O	kWhr/yr	
Blower	349,000	6.00	3,320,163	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total			3,320,163	

Reagent Use & Other Operating Costs

Trona use - 1.5 NSR	76.15	lb/hr SO2	423.11	lb/hr Trona
Solid Waste Disposal	1,489	ton/yr DSI unreacted sorbent and reaction byproducts		

Operating Cost Calculations

Utilization Rate	100%	Annual Operating Hours		8,760			
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	2,190	$ 147,892	$/Hr, 2.0 hr/8 hr shift, 2,190 hr/yr
Supervisor	15%	of Op Labor			NA	$ 22,184	% of Operator Costs
Maintenance							
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	1,095	$ 73,946	$/Hr, 1.0 hr/8 hr shift, 1,095 hr/yr
Maint Mtls	100%	of Maintenance Labor			NA	$ 73,946	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.073	$/kwh	379.0	kW-hr	3,320,163	$ 242,289	$/kwh, 379.0 kW-hr, 8760 hr/yr, 100% utilization
Water			N/A	gpm			
Compressed Air	0.481	$/kscf	2.0	scfm/kacfm	366,869	$ 176,601	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization
Cooling Water			N/A	gpm			
Solid Waste Disposal	63.34	$/ton	0.2	ton/hr	1,489	$ 94,296	$/ton, 0.2 ton/hr, 8760 hr/yr, 100% utilization
Trona	285.00	$/ton	423.1	lb/hr	1,853	$ 528,162	$/ton, 423.1 lb/hr, 8760 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	1,388	bags	N/A	$ 142,970	$/bag, 1,388 bags, 8760 hr/yr, 100% utilization

Appendix C.8

Power Station Boiler No. 11

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.8 – Table C.8-1: Cost Summary
Power Station Boiler No. 11

SO_2 Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Total Annualized Cost $/yr	Pollution Control Cost $/ton
Spray Dry Absorber (SDA)	90%	55.4	498.9	$90,131,245	$12,621,798	$25,298
Dry Sorbent Injection (DSI)	70%	166.3	388.0	$16,488,210	$4,234,824	$10,900

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.8 – Table C.8-2: Summary of Utility, Chemical and Supply Costs

Power Station Boiler No. 11

Operating Unit:	Power Station Boiler No. 11	**Study Year**	2020
Emission Unit Number			
Stack/Vent Number			

Item	2020 Unit Cost	Units	Cost	Year	Data Source	Notes
Operating Labor	68	$/hr	60	2016	EPA SCR Control Cost Manual Spreadsheet	
Maintenance Labor	68	$/hr				Assumed to be equivalent to operating labor
Installation Labor	68	$/hr				Assumed to be equivalent to operating labor
Electricity	0.07	$/kwh			2016-2019 EIA Average prices for the industrial sector in Indiana	
Natural Gas	6.15	$/kscf			2014-2018 EIA Average prices for the Industrial sector in Indiana (latest available 8/20/2020)	
Compressed Air	0.48	$/kscf	0.38	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Chemicals & Supplies						
Lime	183.68	$/ton	145.00	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Trona	285.00	$/ton		2020	Reagent cost for trona from another Barr Engineering Co. Project.	
Fabric Filter Bags	228.02	$/bag	180	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Other						
Sales Tax	7%			2020	Indiana sales tax rate	
Interest Rate	5.50%			2016	EPA SCR Control Cost Manual Spreadsheet	
Solid Waste Disposal	63.34	$/ton	50	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Contingencies	10%	of purchased equip cost (B)			EPA Cost Control Cost Manual Chapter 2	Suggested contingency range of 5% to 15% of total capital investment
Markup on capital investment (retrofit factor)	0%				EPA Cost Control Cost Manual Chapter 2	
Operating Information						
Annual Op. Hrs	8,760	Hours			Emission Inventory Data	
Utilization Rate	100%				Assumed	
Design Capacity	650.0	MMBTU/hr			Boiler Design Capacity	
Equipment Life	20	yrs			Assumed	
Temperature	441	Deg F			Performance test data	
Moisture Content	13.6%				Performance test data	
Actual Flow Rate	323,000	acfm			Performance test data	
Standardized Flow Rate	189,283	scfm @ 68º F	176,377	scfm @ 32º F	Calculated Value	
Dry Std Flow Rate	161,000	dscfm @ 68º F			Performance test data	
Plant Elevation	610	Feet above sea level				Plant elevation
	Baseline Emissions		**lb/hr**	**ton/year**		
Pollutant	**Lb/Hr**	**Ton/Year**	**ppmv**	**ppmv**	**lb/mmbtu**	
Nitrous Oxides (NOx)	43.2	189.0	37	37.4		Emission inventory data
Sulfur Dioxides (SO2)	126.6	554.4	79	78.7		Emission inventory data
SDA - SO_2 Control Efficiency	90%				EPA fact sheet for flue gas desulfurization (new installations) https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf	
DSI - SO_2 Control Efficiency	70%				Control efficiency is based on trona as injected reagent.	

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.8 – Table C.8-3: SO_2 Control Spray Dry Absorber (SDA)

Power Station Boiler No. 11

Operating Unit: **Power Station Boiler No. 11**

Emission Unit Number	0		Stack/Vent Number	0	
Design Capacity	650	MMBtu/hr	Standardized Flow Rate	176,377	scfm @ 32º F
Utilization Rate	100%		Temperature	441	Deg F
Annual Operating Hours	8,760	Hours	Moisture Content	13.6%	
Annual Interest Rate	5.5%		Actual Flow Rate	323,000	acfm
Equipment Life	20	yrs	Standardized Flow Rate	189,283	scfm @ 68º F
			Dry Std Flow Rate	161,000	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**32,689,411**
Purchased Equipment Total (B)	22%	of control device cost (A)	**39,881,082**
Installation - Standard Costs	74%	of purchased equip cost (B)	29,512,001
Installation - Site Specific Costs			NA
Installation Total			29,512,001
Total Direct Capital Cost, DC			69,393,083
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	20,738,163
Total Capital Investment (TCI) = DC + IC			**90,131,245**
Adjusted TCI for Replacment Parts			**89,774,258**
TCI with Retrofit Factor			**89,774,258**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	1,195,479
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	11,426,319
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**12,621,798**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc.**	**Conc. Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10						0.0	-	NA
PM2.5						0.0	-	NA
Total Particulates						0.0	-	NA
Nitrous Oxides (NOx)						0.0	-	NA
Sulfur Dioxide (SO_2)		554.4	90%			55.4	498.9	25,298
Sulfuric Acid Mist						0.00	-	NA
Fluorides						0.0	-	NA
Volatile Organic Compounds (VOC)						0.0	-	NA
Carbon Monoxide (CO)						0.0	-	NA
Lead (Pb)						0.00	-	NA

Notes & Assumptions

1 Capital cost estimate based on mid-range of EPA spray dry fact sheet $/(MMBtu/hr): https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf
2 Costs scaled up to design airflow using the 6/10 power law
3 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.8 – Table C.8-3: SO_2 Control Spray Dry Absorber (SDA)

Power Station Boiler No. 11

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (A) [1]		**32,689,411**
Purchased Equipment Costs (A) - Absorber + packing + auxiliary equipment, EC		
Instrumentation	10% of control device cost (A)	3,268,941
State Sales Taxes	7.0% of control device cost (A)	2,288,259
Freight	5% of control device cost (A)	1,634,471
Purchased Equipment Total (B)	22%	**39,881,082**
Installation		
Foundations & supports	4% of purchased equip cost (B)	1,595,243
Handling & erection	50% of purchased equip cost (B)	19,940,541
Electrical	8% of purchased equip cost (B)	3,190,487
Piping	1% of purchased equip cost (B)	398,811
Insulation	7% of purchased equip cost (B)	2,791,676
Painting	4% of purchased equip cost (B)	1,595,243
Installation Subtotal Standard Expenses	74%	**29,512,001**
Other Specific Costs (see summary)		
Site Preparation, as required	N/A Site Specific	-
Buildings, as required	N/A Site Specific	-
Site Specific - Other	N/A Site Specific	-
Total Site Specific Costs		NA
Installation Total		**29,512,001**
Total Direct Capital Cost, DC		**69,393,083**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	3,988,108
Construction & field expenses	20% of purchased equip cost (B)	7,976,216
Contractor fees	10% of purchased equip cost (B)	3,988,108
Start-up	1% of purchased equip cost (B)	398,811
Performance test	1% of purchased equip cost (B)	398,811
Model Studies	N/A of purchased equip cost (B)	-
Contingencies	10% of purchased equip cost (B)	3,988,108
Total Indirect Capital Costs, IC	52% of purchased equip cost (B)	**20,738,163**
Total Capital Investment (TCI) = DC + IC		**90,131,245**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		**89,774,258**
Total Capital Investment (TCI) with Retrofit Factor	0%	**89,774,258**
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	67.53 $/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 100% utilization	147,892
Supervisor	15% of Op., 0.0 , 8760 hr/yr, 100% utilization	22,184
Maintenance		
Maintenance Labor	67.53 $/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 100% utilization	73,946
Maintenance Materials	100% of maintenance labor costs	73,946
Utilities, Supplies, Replacements & Waste Management		
Electricity	0.07 $/kwh, 584.6 kW-hr, 8760 hr/yr, 100% utilization	373,731
Compressed Air	0.48 $/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization	163,444
N/A		-
SW Disposal	63.34 $/ton, 0.1 ton/hr, 8760 hr/yr, 100% utilization	70,238
Lime	183.68 $/ton, 171.3 lb/hr, 8760 hr/yr, 100% utilization	137,780
Filter Bags	228.02 $/bag, 1,285 bags, 8760 hr/yr, 100% utilization	132,319
N/A		
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
Total Annual Direct Operating Costs		**1,195,479**
Indirect Operating Costs		
Overhead	60% of total labor and material costs	190,780
Administration (2% total capital costs)	2% of total capital costs (TCI)	1,795,485
Property tax (1% total capital costs)	1% of total capital costs (TCI)	897,743
Insurance (1% total capital costs)	1% of total capital costs (TCI)	897,743
Capital Recovery	0.0837 for a 20- year equipment life and a 5.5% interest rate	7,644,568
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**11,426,319**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**12,621,798**

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.8 – Table C.8-3: SO_2 Control Spray Dry Absorber (SDA)

Power Station Boiler No. 11

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:	**Filter Bags**		
Equipment Life	3	years	
CRF	0.3707		
Rep part cost per unit	228.02	$/bag	
Amount Required	1285		
Total Rep Parts Cost	328,070	Cost adjusted for freight & sales tax	
Installation Labor	28,917	10 min per bag	EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**356,987**		
Annualized Cost	**132,319**		

Electrical Use

	Flow acfm	D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	323,000	10.00			5,121,359	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total					5,121,359	

Reagents and Other Operating Costs

Lime Use Rate	1.30	lb-mole CaO/lb-mole SO2	171.26	lb/hr Lime
Solid Waste Disposal	1,109	ton/yr GSA unreacted sorbent and reaction byproducts		

Operating Cost Calculations

Utilization Rate	100%	Annual Operating Hours		8,760				
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***		**Annual Cost**	**Comments**
Operating Labor								
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	2,190	$	147,892	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 100% utilization
Supervisor	15%	of Op.			NA	$	22,184	of Op., 0.0 , 8760 hr/yr, 100% utilization
Maintenance								
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	1,095	$	73,946	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 100% utilization
Maint Mtls	100	% of Maintenance Labor			NA	$	73,946	% of Maintenance Labor, 0.0 , 8760 hr/yr, 100% utilization
Utilities, Supplies, Replacements & Waste Management								
Electricity	0.073	$/kwh	584.6	kW-hr	5,121,359	$	373,731	$/kwh, 584.6 kW-hr, 8760 hr/yr, 100% utilization
Compressed Air	0.481	$/kscf	2	scfm/kacfm	339,538	$	163,444	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization
Water	5.129	$/mgal		gpm				$/mgal, 0 gpm, 8760 hr/yr, 100% utilization
SW Disposal	63.34	$/ton	0.13	ton/hr	1,109	$	70,238	$/ton, 0.1 ton/hr, 8760 hr/yr, 100% utilization
Lime	183.68	$/ton	171.3	lb/hr	750	$	137,780	$/ton, 171.3 lb/hr, 8760 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	1,285	bags	N/A	$	132,319	$/bag, 1,285 bags, 8760 hr/yr, 100% utilization

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix C.8 – Table C.8-4: SO_2 Control Dry Sorbent Injection (DSI)

Power Station Boiler No. 11

Operating Unit: **Power Station Boiler No. 11**

Emission Unit Number			Stack/Vent Number		
Design Capacity	650	MMBtu/hr	Standardized Flow Rate	176,377	scfm @ 32º F
Utilization Rate	100%		Exhaust Temperature	441	Deg F
Annual Operating Hours	8,760	hr/yr	Exhaust Moisture Content	13.6%	
Annual Interest Rate	5.50%		Actual Flow Rate	323,000	acfm
Control Equipment Life	20	yrs	Standardized Flow Rate	189,283	scfm @ 68º F
Plant Elevation	610	ft	Dry Std Flow Rate	161,000	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**6,109,530**
Purchased Equipment Total (B)	22%	of control device cost (A)	**7,453,627**
Installation - Standard Costs	74%	of purchased equip cost (B)	5,515,684
Installation - Site Specific Costs			N/A
Installation Total			5,515,684
Total Direct Capital Cost, DC			12,969,311
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	3,875,886
Total Capital Investment (TCI) = DC + IC			**16,488,210**
Adjusted TCI for Replacement Parts			16,488,210
Total Capital Investment (TCI) with Retrofit Factor			**16,488,210**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	1,872,475
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	2,362,350
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,234,824**

Emission Control Cost Calculation

Pollutant	Max Emis Lb/Hr	Annual Ton/Yr	Cont Eff %	Cont Emis Ton/Yr	Reduction Ton/Yr	Cont Cost $/Ton Rem
PM10						
PM2.5						
Total Particulates						
Nitrous Oxides (NOx)						
Sulfur Dioxide (SO2)	126.56	554.35	70%	166.31	388.05	$10,900
Sulfuric Acid Mist (H2SO4)						
Fluorides						
Volatile Organic Compounds (VOC)						
Carbon Monoxide (CO)						
Lead (Pb)						

Notes & Assumptions

1. Baghouse capital cost estimate based on EPA-R05-OAR-2010-0954-0079, ancillary equipment from other Barr Engineering projects
2. Costs scaled up to design airflow using the 6/10 power law
3. Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.8 – Table C.8-4: SO_2 Control Dry Sorbent Injection (DSI)
Power Station Boiler No. 11

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) [1]			**6,109,530**
Purchased Equipment Costs (A) - Injection System + auxiliary equipment, EC			
Instrumentation	10%	Included in vendor estimate	610,953
State Sales Taxes	7.0%	of control device cost (A)	427,667
Freight	5%	of control device cost (A)	305,477
Purchased Equipment Total (B)	22%		**7,453,627**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	298,145
Handling & erection	50%	of purchased equip cost (B)	3,726,813
Electrical	8%	of purchased equip cost (B)	596,290
Piping	1%	of purchased equip cost (B)	74,536
Insulation	7%	of purchased equip cost (B)	521,754
Painting	4%	Included in vendor estimate	298,145
Installation Subtotal Standard Expenses	74%		**5,515,684**
Other Specific Costs (see summary)			
Site Preparation, as required	N/A	Site Specific	
Buildings, as required	N/A	Site Specific	
Lost Production for Tie-In	N/A	Site Specific	
Total Site Specific Costs			N/A
Installation Total			**5,515,684**
Total Direct Capital Cost, DC			**12,969,311**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	745,363
Construction & field expenses	20%	of purchased equip cost (B)	1,490,725
Contractor fees	10%	of purchased equip cost (B)	745,363
Start-up	1%	of purchased equip cost (B)	74,536
Performance test	1%	of purchased equip cost (B)	74,536
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	745,363
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**3,875,886**
Total Capital Investment (TCI) = DC + IC			**16,845,196**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**16,488,210**
Total Capital Investment (TCI) with Retrofit Factor	0%		**16,488,210**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	67.53	$/Hr	147,892
Supervisor	0.15	of Op Labor	22,184
Maintenance			
Maintenance Labor	67.53	$/Hr	73,946
Maintenance Materials	100	% of Maintenance Labor	73,946
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.07	$/kwh, 350.8 kW-hr, 8760 hr/yr, 100% utilization	224,239
N/A			-
Compressed Air	0.48	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization	163,444
N/A			-
Solid Waste Disposal	63.34	$/ton, 0.3 ton/hr, 8760 hr/yr, 100% utilization	156,716
Trona	285.00	$/ton, 703.2 lb/hr, 8760 hr/yr, 100% utilization	877,789
Filter Bags	228.02	$/bag, 1,285 bags, 8760 hr/yr, 100% utilization	132,319
N/A			-
N/A			-
N/A			-
N/A			-
Total Annual Direct Operating Costs			**1,872,475**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	190,780
Administration (2% total capital costs)	2%	of total capital costs (TCI)	329,764
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	164,882
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	164,882
Capital Recovery	0.0837	for a 20-year equipment life and a 5.5% interest rate	1,379,722
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery costs	**2,362,350**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,234,824**

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.8 – Table C.8-4: SO_2 Control Dry Sorbent Injection (DSI)
Power Station Boiler No. 11

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment: **Filter Bags**

Equipment Life	3	years
CRF	0.3707	
Rep part cost per unit	228.02	$/bag
Amount Required	1285	Bags
Total Rep Parts Cost	328,070	Cost adjusted for freight, sales tax, and bag disposal
Installation Labor	28,917	20 min per bag
Total Installed Cost	**356,987**	
Annualized Cost	**132,319**	

Electrical Use

	Flow acfm	D P in H2O	kWhr/yr	
Blower	323,000	6.00	3,072,815	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total			3,072,815	

Reagent Use & Other Operating Costs

Trona use - 1.5 NSR	126.56 lb/hr SO2	703.19 lb/hr Trona
Solid Waste Disposal	2,474	ton/yr DSI unreacted sorbent and reaction byproducts

Operating Cost Calculations

Utilization Rate	100%	Annual Operating Hours		8,760			
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	2,190	$ 147,892	$/Hr, 2.0 hr/8 hr shift, 2,190 hr/yr
Supervisor	15%	of Op Labor			NA	$ 22,184	% of Operator Costs
Maintenance							
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	1,095	$ 73,946	$/Hr, 1.0 hr/8 hr shift, 1,095 hr/yr
Maint Mtls	100%	of Maintenance Labor			NA	$ 73,946	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.073	$/kwh	350.8	kW-hr	3,072,815	$ 224,239	$/kwh, 350.8 kW-hr, 8760 hr/yr, 100% utilization
Water			N/A	gpm			
Compressed Air	0.481	$/kscf	2.0	scfm/kacfm	339,538	$ 163,444	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization
Cooling Water			N/A	gpm			
Solid Waste Disposal	63.34	$/ton	0.3	ton/hr	2,474	$ 156,716	$/ton, 0.3 ton/hr, 8760 hr/yr, 100% utilization
Trona	285.00	$/ton	703.2	lb/hr	3,080	$ 877,789	$/ton, 703.2 lb/hr, 8760 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	1,285	bags	N/A	$ 132,319	$/bag, 1,285 bags, 8760 hr/yr, 100% utilization

Appendix C.9

Power Station Boiler No. 12

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Control
Appendix C.9 – Table C.9-1: Cost Summary
Power Station Boiler No. 12

SO_2 Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Total Annualized Cost $/yr	Pollution Control Cost $/ton
Spray Dry Absorber (SDA)	90%	70.3	632.5	$90,131,245	$12,855,776	$20,325
Dry Sorbent Injection (DSI)	70%	210.8	492.0	$18,715,200	$4,940,776	$10,000

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Control

Appendix C.9 – Table C.9-2: Summary of Utility, Chemical and Supply Costs

Power Station Boiler No. 12

Operating Unit:	Power Station Boiler No. 12	**Study Year**	2020
Emission Unit Number			
Stack/Vent Number			

Item	2020 Unit Cost	Units	Cost	Year	Data Source	Notes
Operating Labor	68	$/hr	60	2016	EPA SCR Control Cost Manual Spreadsheet	
Maintenance Labor	68	$/hr				Assumed to be equivalent to operating labor
Installation Labor	68	$/hr				Assumed to be equivalent to operating labor
Electricity	0.07	$/kwh			2016-2019 EIA Average prices for the industrial sector in Indiana	
Natural Gas	6.15	$/kscf			2014-2018 EIA Average prices for the Industrial sector in Indiana (latest available 8/20/2020)	
Compressed Air	0.48	$/kscf	0.38	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Chemicals & Supplies						
Lime	183.68	$/ton	145.00	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Trona	285.00	$/ton		2020	Reagent cost for trona from another Barr Engineering Co. Project.	
Fabric Filter Bags	228.02	$/bag	180	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Other						
Sales Tax	7%			2020	Indiana sales tax rate	
Interest Rate	5.50%			2016	EPA SCR Control Cost Manual Spreadsheet	
Solid Waste Disposal	63.34	$/ton	50	2012	Taconite FIP Docket - Cost estimate for United Taconite	
Contingencies	10%	of purchased equip cost (B)			EPA Cost Control Cost Manual Chapter 2	Suggested contingency range of 5% to 15% of total capital investment
Markup on capital investment (retrofit factor)	0%				EPA Cost Control Cost Manual Chapter 2	
Operating Information						
Annual Op. Hrs	8,760	Hours			Emission Inventory Data	
Utilization Rate	100%				Assumed	
Design Capacity	650.0	MMBTU/hr			Boiler Design Capacity	
Equipment Life	20	yrs			Assumed	
Temperature	421	Deg F			Performance test data	
Moisture Content	11.3%				Performance test data	
Actual Flow Rate	399,000	acfm			Performance test data	
Standardized Flow Rate	239,128	scfm @ 68º F	222,824	scfm @ 32º F	Calculated Value	
Dry Std Flow Rate	202,000	dscfm @ 68º F			Performance test data	
Plant Elevation	610	Feet above sea level				Plant elevation
	Baseline Emissions		**lb/hr**	**ton/year**		
Pollutant	**Lb/Hr**	**Ton/Year**	**ppmv**	**ppmv**	**lb/mmbtu**	
Nitrous Oxides (NOx)	46.6	204.0	32	32.2		Emission inventory data
Sulfur Dioxides (SO2)	160.5	702.8	80	79.6		Emission inventory data
SDA - SO_2 Control Efficiency	90%				EPA fact sheet for flue gas desulfurization (new installations) https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf	
DSI - SO_2 Control Efficiency	70%				Control efficiency is based on trona as injected reagent.	

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Control
Appendix C.9 – Table C.9-3: SO_2 Control Spray Dry Absorber (SDA)
Power Station Boiler No. 12

Operating Unit: **Power Station Boiler No. 12**

Emission Unit Number	0		Stack/Vent Number	0	
Design Capacity	650	MMBtu/hr	Standardized Flow Rate	222,824	scfm @ 32º F
Utilization Rate	100%		Temperature	421	Deg F
Annual Operating Hours	8,760	Hours	Moisture Content	11.3%	
Annual Interest Rate	5.5%		Actual Flow Rate	399,000	acfm
Equipment Life	20	yrs	Standardized Flow Rate	239,128	scfm @ 68º F
			Dry Std Flow Rate	202,000	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**32,689,411**
Purchased Equipment Total (B)	22%	of control device cost (A)	**39,881,082**
Installation - Standard Costs	74%	of purchased equip cost (B)	29,512,001
Installation - Site Specific Costs			NA
Installation Total			29,512,001
Total Direct Capital Cost, DC			69,393,083
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	20,738,163
Total Capital Investment (TCI) = DC + IC			**90,131,245**
Adjusted TCI for Replacment Parts			**89,690,262**
TCI with Retrofit Factor			**89,690,262**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	1,408,712
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	11,447,064
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**12,855,776**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual T/Yr**	**Cont Eff %**	**Exit Conc.**	**Conc. Units**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10						0.0	-	NA
PM2.5						0.0	-	NA
Total Particulates						0.0	-	NA
Nitrous Oxides (NOx)						0.0	-	NA
Sulfur Dioxide (SO_2)		702.8	90%			70.3	632.5	20,325
Sulfuric Acid Mist						0.00	-	NA
Fluorides						0.0	-	NA
Volatile Organic Compounds (VOC)						0.0	-	NA
Carbon Monoxide (CO)						0.0	-	NA
Lead (Pb)						0.00	-	NA

Notes & Assumptions

1. Capital cost estimate based on mid-range of EPA spray dry fact sheet $/(MMBtu/hr): https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf
2. Costs scaled up to design airflow using the 6/10 power law
3. Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Control

Appendix C.9 – Table C.9-3: SO_2 Control Spray Dry Absorber (SDA)

Power Station Boiler No. 12

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (A) [1]		**32,689,411**
Purchased Equipment Costs (A) - Absorber + packing + auxiliary equipment, EC		
Instrumentation	10% of control device cost (A)	3,268,941
State Sales Taxes	7.0% of control device cost (A)	2,288,259
Freight	5% of control device cost (A)	1,634,471
Purchased Equipment Total (B)	22%	**39,881,082**
Installation		
Foundations & supports	4% of purchased equip cost (B)	1,595,243
Handling & erection	50% of purchased equip cost (B)	19,940,541
Electrical	8% of purchased equip cost (B)	3,190,487
Piping	1% of purchased equip cost (B)	398,811
Insulation	7% of purchased equip cost (B)	2,791,676
Painting	4% of purchased equip cost (B)	1,595,243
Installation Subtotal Standard Expenses	74%	**29,512,001**
Other Specific Costs (see summary)		
Site Preparation, as required	N/A Site Specific	-
Buildings, as required	N/A Site Specific	-
Site Specific - Other	N/A Site Specific	-
Total Site Specific Costs		NA
Installation Total		**29,512,001**
Total Direct Capital Cost, DC		**69,393,083**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	3,988,108
Construction & field expenses	20% of purchased equip cost (B)	7,976,216
Contractor fees	10% of purchased equip cost (B)	3,988,108
Start-up	1% of purchased equip cost (B)	398,811
Performance test	1% of purchased equip cost (B)	398,811
Model Studies	N/A of purchased equip cost (B)	-
Contingencies	10% of purchased equip cost (B)	3,988,108
Total Indirect Capital Costs, IC	52% of purchased equip cost (B)	**20,738,163**
Total Capital Investment (TCI) = DC + IC		**90,131,245**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost		**89,690,262**
Total Capital Investment (TCI) with Retrofit Factor	0%	**89,690,262**
OPERATING COSTS		
Direct Annual Operating Costs, DC		
Operating Labor		
Operator	67.53 $/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 100% utilization	147,892
Supervisor	15% of Op., 0.0 , 8760 hr/yr, 100% utilization	22,184
Maintenance		
Maintenance Labor	67.53 $/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 100% utilization	73,946
Maintenance Materials	100% of maintenance labor costs	73,946
Utilities, Supplies, Replacements & Waste Management		
Electricity	0.07 $/kwh, 722.2 kW-hr, 8760 hr/yr, 100% utilization	461,668
Compressed Air	0.48 $/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization	201,902
N/A		-
SW Disposal	63.34 $/ton, 0.2 ton/hr, 8760 hr/yr, 100% utilization	89,047
Lime	183.68 $/ton, 217.1 lb/hr, 8760 hr/yr, 100% utilization	174,676
Filter Bags	228.02 $/bag, 1,587 bags, 8760 hr/yr, 100% utilization	163,452
N/A		
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
N/A		-
Total Annual Direct Operating Costs		**1,408,712**
Indirect Operating Costs		
Overhead	60% of total labor and material costs	190,780
Administration (2% total capital costs)	2% of total capital costs (TCI)	1,793,805
Property tax (1% total capital costs)	1% of total capital costs (TCI)	896,903
Insurance (1% total capital costs)	1% of total capital costs (TCI)	896,903
Capital Recovery	0.0837 for a 20- year equipment life and a 5.5% interest rate	7,668,673
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**11,447,064**
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**12,855,776**

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Control
Appendix C.9 – Table C.9-3: SO_2 Control Spray Dry Absorber (SDA)
Power Station Boiler No. 12

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment: **Filter Bags**

Equipment Life	3	years	
CRF	0.3707		
Rep part cost per unit	228.02	$/bag	
Amount Required	1587		
Total Rep Parts Cost	405,262	Cost adjusted for freight & sales tax	
Installation Labor	35,721	10 min per bag	EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**440,984**		
Annualized Cost	**163,452**		

Electrical Use

	Flow acfm	D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	399,000	10.00			6,326,384	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total					6,326,384	

Reagents and Other Operating Costs

Lime Use Rate	1.30	lb-mole CaO/lb-mole SO2	217.12 lb/hr Lime
Solid Waste Disposal	1,406	ton/yr GSA unreacted sorbent and reaction byproducts	

Operating Cost Calculations

Utilization Rate 100% | Annual Operating Hours 8,760

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***		**Annual Cost**	**Comments**
Operating Labor								
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	2,190	$	147,892	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 100% utilization
Supervisor	15%	of Op.			NA	$	22,184	of Op., 0.0 , 8760 hr/yr, 100% utilization
Maintenance								
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	1,095	$	73,946	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 100% utilization
Maint Mtls	100	% of Maintenance Labor			NA	$	73,946	% of Maintenance Labor, 0.0 , 8760 hr/yr, 100% utilization
Utilities, Supplies, Replacements & Waste Management								
Electricity	0.073	$/kwh	722.2	kW-hr	6,326,384	$	461,668	$/kwh, 722.2 kW-hr, 8760 hr/yr, 100% utilization
Compressed Air	0.481	$/kscf	2	scfm/kacfm	419,429	$	201,902	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization
Water	5.129	$/mgal		gpm				$/mgal, 0 gpm, 8760 hr/yr, 100% utilization
SW Disposal	63.34	$/ton	0.16	ton/hr	1,406	$	89,047	$/ton, 0.2 ton/hr, 8760 hr/yr, 100% utilization
Lime	183.68	$/ton	217.1	lb/hr	951	$	174,676	$/ton, 217.1 lb/hr, 8760 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	1,587	bags	N/A	$	163,452	$/bag, 1,587 bags, 8760 hr/yr, 100% utilization

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Control

Appendix C.9 – Table C.9-4: SO_2 Control Dry Sorbent Injection (DSI)

Power Station Boiler No. 12

Operating Unit: **Power Station Boiler No. 12**

Emission Unit Number			Stack/Vent Number		
Design Capacity	650	MMBtu/hr	Standardized Flow Rate	222,824	scfm @ 32º F
Utilization Rate	100%		Exhaust Temperature	421	Deg F
Annual Operating Hours	8,760	hr/yr	Exhaust Moisture Content	11.3%	
Annual Interest Rate	5.50%		Actual Flow Rate	399,000	acfm
Control Equipment Life	20	yrs	Standardized Flow Rate	239,128	scfm @ 68º F
Plant Elevation	610	ft	Dry Std Flow Rate	202,000	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**6,947,695**
Purchased Equipment Total (B)	22%	of control device cost (A)	**8,476,187**
Installation - Standard Costs	74%	of purchased equip cost (B)	6,272,379
Installation - Site Specific Costs			N/A
Installation Total			6,272,379
Total Direct Capital Cost, DC			14,748,566
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	4,407,617
Total Capital Investment (TCI) = DC + IC			**18,715,200**
Adjusted TCI for Replacement Parts			18,715,200
Total Capital Investment (TCI) with Retrofit Factor			**18,715,200**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	2,271,859
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	2,668,916
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,940,776**

Emission Control Cost Calculation

Pollutant	**Max Emis Lb/Hr**	**Annual Ton/Yr**	**Cont Eff %**	**Cont Emis Ton/Yr**	**Reduction Ton/Yr**	**Cont Cost $/Ton Rem**
PM10						
PM2.5						
Total Particulates						
Nitrous Oxides (NOx)						
Sulfur Dioxide (SO2)	160.46	702.80	70%	210.84	491.96	$10,000
Sulfuric Acid Mist (H2SO4)						
Fluorides						
Volatile Organic Compounds (VOC)						
Carbon Monoxide (CO)						
Lead (Pb)						

Notes & Assumptions

1. Baghouse capital cost estimate based on EPA-R05-OAR-2010-0954-0079, ancillary equipment from other Barr Engineering projects
2. Costs scaled up to design airflow using the 6/10 power law
3. Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
4. Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1

ArcelorMittal Burns Harbor
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Control
Appendix C.9 – Table C.9-4: SO_2 Control Dry Sorbent Injection (DSI)
Power Station Boiler No. 12

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) [1]			**6,947,695**
Purchased Equipment Costs (A) - Injection System + auxiliary equipment, EC			
Instrumentation	10%	Included in vendor estimate	694,769
State Sales Taxes	7.0%	of control device cost (A)	486,339
Freight	5%	of control device cost (A)	347,385
Purchased Equipment Total (B)	22%		**8,476,187**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	339,047
Handling & erection	50%	of purchased equip cost (B)	4,238,094
Electrical	8%	of purchased equip cost (B)	678,095
Piping	1%	of purchased equip cost (B)	84,762
Insulation	7%	of purchased equip cost (B)	593,333
Painting	4%	Included in vendor estimate	339,047
Installation Subtotal Standard Expenses	74%		**6,272,379**
Other Specific Costs (see summary)			
Site Preparation, as required	N/A	Site Specific	
Buildings, as required	N/A	Site Specific	
Lost Production for Tie-In	N/A	Site Specific	
Total Site Specific Costs			N/A
Installation Total			**6,272,379**
Total Direct Capital Cost, DC			**14,748,566**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	847,619
Construction & field expenses	20%	of purchased equip cost (B)	1,695,237
Contractor fees	10%	of purchased equip cost (B)	847,619
Start-up	1%	of purchased equip cost (B)	84,762
Performance test	1%	of purchased equip cost (B)	84,762
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	847,619
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**4,407,617**
Total Capital Investment (TCI) = DC + IC			**19,156,183**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**18,715,200**
Total Capital Investment (TCI) with Retrofit Factor	0%		**18,715,200**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	67.53	$/Hr	147,892
Supervisor	0.15	of Op Labor	22,184
Maintenance			
Maintenance Labor	67.53	$/Hr	73,946
Maintenance Materials	100	% of Maintenance Labor	73,946
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.07	$/kwh, 433.3 kW-hr, 8760 hr/yr, 100% utilization	277,001
N/A			-
Compressed Air	0.48	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization	201,902
N/A			-
Solid Waste Disposal	63.34	$/ton, 0.4 ton/hr, 8760 hr/yr, 100% utilization	198,684
Trona	285.00	$/ton, 891.5 lb/hr, 8760 hr/yr, 100% utilization	1,112,854
Filter Bags	228.02	$/bag, 1,587 bags, 8760 hr/yr, 100% utilization	163,452
N/A			-
N/A			-
N/A			-
N/A			-
Total Annual Direct Operating Costs			**2,271,859**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	190,780
Administration (2% total capital costs)	2%	of total capital costs (TCI)	374,304
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	187,152
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	187,152
Capital Recovery	0.0837	for a 20-year equipment life and a 5.5% interest rate	1,566,075
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery costs	**2,668,916**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,940,776**

ArcelorMittal Burns Harbor

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Control

Appendix C.9 – Table C.9-4: SO_2 Control Dry Sorbent Injection (DSI)

Power Station Boiler No. 12

Capital Recovery Factors

Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment: **Filter Bags**

Equipment Life	3	years
CRF	0.3707	
Rep part cost per unit	228.02	$/bag
Amount Required	1587	Bags
Total Rep Parts Cost	405,262	Cost adjusted for freight, sales tax, and bag disposal
Installation Labor	35,721	20 min per bag
Total Installed Cost	**440,984**	
Annualized Cost	**163,452**	

Electrical Use

	Flow acfm	D P in H2O	kWhr/yr	
Blower	399,000	6.00	3,795,831	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total			3,795,831	

Reagent Use & Other Operating Costs

Trona use - 1.5 NSR	160.46	lb/hr SO2	891.50	lb/hr Trona
Solid Waste Disposal	3,137	ton/yr DSI unreacted sorbent and reaction byproducts		

Operating Cost Calculations

Utilization Rate	100%	Annual Operating Hours		8,760			
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	2,190	$ 147,892	$/Hr, 2.0 hr/8 hr shift, 2,190 hr/yr
Supervisor	15%	of Op Labor			NA	$ 22,184	% of Operator Costs
Maintenance							
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	1,095	$ 73,946	$/Hr, 1.0 hr/8 hr shift, 1,095 hr/yr
Maint Mtls	100%	of Maintenance Labor			NA	$ 73,946	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.073	$/kwh	433.3	kW-hr	3,795,831	$ 277,001	$/kwh, 433.3 kW-hr, 8760 hr/yr, 100% utilization
Water			N/A	gpm			
Compressed Air	0.481	$/kscf	2.0	scfm/kacfm	419,429	$ 201,902	$/kscf, 2.0 scfm/kacfm, 8760 hr/yr, 100% utilization
Cooling Water			N/A	gpm			
Solid Waste Disposal	63.34	$/ton	0.4	ton/hr	3,137	$ 198,684	$/ton, 0.4 ton/hr, 8760 hr/yr, 100% utilization
Trona	285.00	$/ton	891.5	lb/hr	3,905	$ 1,112,854	$/ton, 891.5 lb/hr, 8760 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	1,587	bags	N/A	$ 163,452	$/bag, 1,587 bags, 8760 hr/yr, 100% utilization

Appendix D

2008 ArcelorMittal Burns Harbor BART Modeling Report

Prepared for: ArcelorMittal Burns Harbor LLC
Burns Harbor, Indiana

Source-Specific BART Modeling Report: ArcelorMittal Burns Harbor LLC

ENSR Corporation
August 2008
Document No.: 12591-001-0600

ENSR | AECOM

Prepared for: Mittal Steel USA
Burns Harbor, Indiana

Source-Specific BART Modeling Report: ArcelorMittal Burns Harbor LLC

Prepared By: Jeffrey Connors

Reviewed By: Olga Kostrova

ENSR Corporation
August 2008
Document No.: 12591-001-0600

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1.0 Introduction

1.1 Objectives

The Regional Haze Rule regulations require Best Available Retrofit Technology (BART) for any BART-eligible source that "emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility" in any mandatory Class I federal area. Pursuant to federal regulations, states and/or local regulatory agencies have the option of exempting a BART-eligible source from the BART requirements based on dispersion modeling demonstrating that the source cannot reasonably be anticipated to cause or contribute to visibility impairment in a Class I area. Indiana's BART rule at 326 IAC 26-1-6 allows Burns Harbor to submit an analysis sufficient to demonstrate that it is not subject to BART. That analysis was timely submitted in May 2008 within ninety (90) days after receiving IDEM's BART notice. IDEM identified some outdated emission factors that were inadvertently included in the May 2008 Report. This revised Source-Specific BART Modeling Report updates the May 2008 Report with improved model inputs based on the most recent and accurate emission information available for each emissions unit.

ArcelorMittal Burns Harbor LLC (Burns Harbor) is a facility located on Lake Michigan in northwestern Indiana, approximately 50 miles southeast of Chicago. The Burns Harbor facility is a steelmaking facility that has been identified by Indiana Department of Environmental Management (IDEM) as being a BART-eligible source. The purpose of this Report is to summarize the procedures by which a refined air dispersion modeling analysis was conducted for the Burns Harbor facility and to transmit an analysis of the modeling results in accordance with 326 IAC 26-1-6 in support of a refined assessment of Burns Harbor's contribution to visibility impairment in Class I areas.

The first step in the BART process is to model the visibility impact of baseline emissions to determine whether the BART-eligible sources at a facility are subject to BART. According to the BART rule (326 IAC 26-1-4), a facility will be exempt from BART if its 98th percentile visibility impacts for baseline emissions are less than 0.5 delta-deciviews (delta-dv) in each Class I area for each modeled year. The refined modeling provided in this Report demonstrates that Burns Harbor's impact on all relevant Class I Areas is comfortably below 0.5 deciviews and cannot reasonably be anticipated to cause or contribute to visibility impairment in a Class I Area.

1.2 Location of Source vs. Relevant Class I Areas

Figure 1-1 shows a plot of the Burns Harbor facility relative to nearby Class I areas. There are no PSD Class I areas within 300 km of the facility, which is the outer extent of the reliability range for predicting impacts with CALPUFF air dispersion modeling. Nonetheless, the four closest Class I areas were included in the modeling to capture possible impacts from the Burns Harbor facility. These Class I areas are listed below:

- Isle Royale National Park (674 km)
- Mammoth Cave National Park (485 km)
- Mingo Wilderness (580 km)
- Seney Wilderness (539 km)

IDEM's CALPUFF modeling screened for potential contributions to visibility impairment from the Burns Harbor facility at these four Class I areas. The refined modeling summarized in this Report offers a more accurate assessment of the potential contribution of Burns Harbor to visibility impairments at any of these far-off Class I areas. This Report describes in detail the procedures used for this refined CALPUFF modeling.

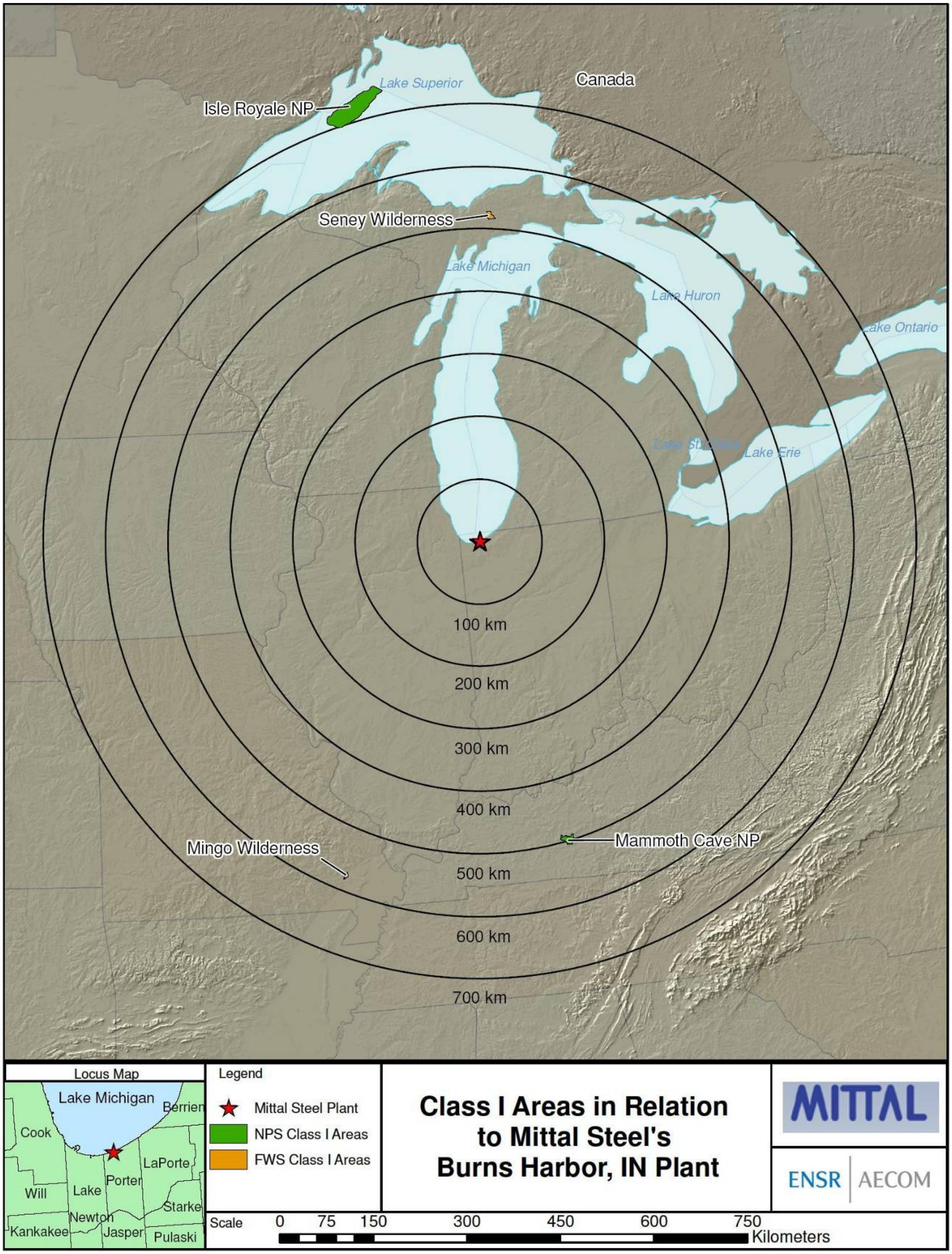
CALPUFF is the only EPA-approved model for predicting impacts for long-range emission transport beyond 50 km. The Guideline on Air Quality Models (GAQM) (Appendix W to 40 CFR Part 51) suggests that CALPUFF "had performed in a reasonable manner, and had no apparent bias toward over or under prediction, so long as the transport distance was limited to less than 300 km". Beyond 300 km, CALPUFF's modeled impacts are less reliable with a tendency toward over predicting impacts.

The closest Class I area is Mammoth Cave NP, located approximately 485 km to the south-southeast well beyond the suggested use of CALPUFF. The modeling analysis in this Report uses CALPUFF as directed by the Midwest Regional Planning Organization (MWRPO) and IDEM with the stipulation that the model's performance has tended toward over prediction of modeled impacts beyond 300 km and the fact that the federal Guidance suggests that its use beyond 300 km may not be reliable or appropriate.

1.3 Organization of Report

Section 2 of this report describes the method for determining the peak 24-hour source emissions that were used as input to the BART modeling. Section 3 describes refinements to the meteorological database and the CALMET processing that provide essential data for predicting the transport of emissions. Section 4 discusses CALPUFF technical options and modeling procedures. Section 5 presents the modeling results. References are provided in Section 6. Appendix A lists meteorological stations that were used for CALMET processing and Appendix B provides documentation of the implementation of the new IMPROVE equation. Appendix C provides a detailed description of the method used to derive the oxides of nitrogen and sulfur dioxide inputs to the model.

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



2.0 Emissions and Source Parameters

The Lake Michigan Air Directors Consortium (LADCO) developed a protocol to be used in the BART CALPUFF modeling for Indiana. The LADCO protocol specifies that "States will use the 24-hour maximum emissions rate between 2002 and 2004. If this data is not available, then a short term "allowable" or "potential emission rate of emissions between the years 2002-2004 will be used. If neither of these types of emission rates is available, then the highest actual annual emissions divided by hours of operation will be applied in CALPUFF." For this Report, we calculate the 24-hour maximum emission rate for the years 2002-2004.

Emission units included in the modeling are of two main types, combustion units and process units. Combustion unit emissions are calculated using actual daily fuel use records from Burns Harbor's computerized database for 2002, 2003, and 2004 and relevant emission factors. The emission factors for combustions units are based on fuel sampling, stack testing, or U.S. EPA's AP-42 (see Table 2-4). The 24-hour emission rate was determined by multiplying the daily fuel use day for each fuel used that day by the appropriate emission factor for each combustion unit for 2002, 2003 and 2004. Emission for each fuel used was summed to determine the total emissions for each unit by day. The 24-hour maximum emission rate was determined by selecting the highest total emissions day for each unit and were used as the maximum 24-hour emissions inputs to the CALPUFF model.

Burns Harbor's Power Station contains multi-fuel Boiler Nos. 7 through 12. The Power Station is operated as one unit with switching between boilers as necessary to provide the needed steam and to maintain backup capabilities. Consequently, fuel use and emissions calculations were determined for the entire Power Station rather than for individual boilers to more accurately reflect 24-hour maximum emissions.

Process unit emissions are calculated using the maximum 24-hour production rate for each process unit during 2002, 2003 and 2004 and appropriate emission factors per unit of production. The process emission factors were derived from stack tests on the same or similar units and from AP-42 emission factors (see Table 2-5). For smaller incidental units (e.g., FM Boiler, Hot Metal Desulfurization, etc.) where only monthly production data were available, the average daily production was calculated by dividing the monthly production by the number of days in the period. The day with the highest calculated sulfur dioxide emission rate and the day with the highest oxides of nitrogen emissions rate from 2002, 2003 or 2004 were selected for each process unit as the maximum 24-hour emission inputs to the CALPUFF model.

Emissions from slag pits and steelmaking fugitives that do not vent through stacks are "volume" sources (see Table 2-1). Without stacks, volume sources have limited velocity at the point of emission and are, thus, not expected to be transported very far away from the emission source. As such, we do not expect these volume sources to contribute to visibility impacts that require the transport of emissions to Class I areas over 480 km away. Nonetheless, we conservatively included the emissions from volume sources in the modeling by adding their emissions to the combustion emissions from the Power Station.

This method combines the highest daily emission rates for each of 26 emission units (+3 volume sources) into a fictitious worst case day. A complex steel manufacturer cannot simultaneously achieve the 24-hour maximum emission rate at all 26+ emission units listed in Table 2-1. While the modeling demonstrates that Burns Harbor's visibility impact is acceptable even using this highly conservative approach (see Table 5-1), This scenario conservatively overestimates the impact on Class I areas. In order to estimate plant emissions on a more realistic basis, we calculated the maximum individual day of plant-wide sulfur dioxide and oxides of nitrogen emissions during the period of 2002 through 2004. Daily sulfur dioxide and oxides of nitrogen emissions from all emission units were summed for each day to obtain the total plant daily emissions. The plant-wide daily sulfur dioxide and oxides of nitrogen emissions for 2002, 2003 and 2004 were scanned to determine the highest daily plant-wide emissions for each of the two pollutants. These maximum 24-hour plant-wide emission rates for sulfur dioxide emissions and for oxides of nitrogen were used as inputs in a separate modeling run summarized in Table 5-2. The modeling results confirm that Burns Harbor is comfortably below the threshold that triggers BART regulation when using this more realistic assessment of the 24-hour maximum emission rate as input to the CALPUFF model.

Table 2-1 provides a summary of the baseline emissions used in the BART CALPUFF model to model the maximum day on an emission unit basis. Table 2-2 provides the modeling parameters that were used in the BART CALPUFF modeling. Table 2-3 provides a summary of the baseline emissions used in the plant-wide maximum emission day modeling. The same modeling parameters in Table 2-2 were used for the plant-wide maximum modeling. Table 2-4 contains the emission factors used to calculate emissions for combustion units. Table 2-5 provides the emission factors used to calculate emissions from process units.

Table 2-1 Burns Harbor Facility Baseline Emission Rates - Maximum by Emission Unit

Stack Description	Peak 24-Hour Emissions (g/s)		Fuel & Production Data Record Frequency
	SO_2	NO_X	
POWER STATION Boiler Nos 7-12	218.31	162.49	Daily
#1 COKE BATTERY PUSHING	1.38	0.27	Monthly
#1 COKE BATTERY UNDERFIRE	64.13	94.53	Daily
#2 COKE BATTERY PUSHING	1.39	0.27	Monthly
#2 COKE BATTERY UNDERFIRE	69.29	5.45	Daily
SINTER WINDBOX STACK	25.20	43.59	Daily
BLAST FCE D CASTHOUSE/FUG	0.00	1.02	Monthly
BLAST FURNACE C STOVES	42.03	4.27	Daily
BLAST FURNACE D STOVES	41.88	4.33	Daily
BLAST FCE C CASTHOUSE/FUG	0.00	0.99	Monthly
STEELMAKING HMD STATION #1	0.30	0.02	Monthly
STEELMAKING HMD STATION #2	0.30	0.02	Monthly
STEELMAKING VESSELS #1 & #2	0.09	2.76	Monthly
STEELMAKING VESSEL #3	0.09	1.53	Monthly
STEELMAKING FM BOILER	0.002	0.47	Monthly
HOT STRIP FURNACE #1	7.74	7.36	Daily
HOT STRIP FURNACE #3	7.93	8.16	Daily
HOT STRIP FURNACE #2	7.95	7.17	Daily
160" PLATE MILL FURNACE #1	18.17	4.09	Daily
160" PLATE MILL FURNACE #2	25.28	4.39	Daily
160" PLATE MILL FURNACE #5	0.00	0.00	Daily
160" PLATE MILL FURNACES 6 & 7	0.01	1.27	Daily
160" PLATE MILL FURNACE #8	0.00	0.00	Daily
110 PLATE MILL FURNACES 1 &2	0.00	0.00	Daily
STEELMAKING HMD STATION #3	0.26	0.02	Monthly
110" Plate Mill Normalizing Fce	0.00	0.00	Daily

Volume Source Description[1]	Model Inputs (g/s)	
	SO_2	NO_x
Blast Furnace C Slag Pit	4.04	0.00
Blast Furnace D Slag Pit	3.36	0.00
Steelmaking Fugitives	0.37	0.99

(1) Total emission from the volume sources were added to the Power Station Source when modeled. Production data frequency is monthly for all volume sources

Table 2-2 Burns Harbor Facility Modeling Stack Parameters

Stack Description	Base Elevation(m)	Stack Height (m)	Diameter (m)	Flow (m^3/s)	Temperature (K)	Exit velocity (m/sec)	UTM Easting (m)	UTM Northing (m)
POWER STATION Boiler Nos 7-12	187.14	67.06	3.43	123.2	505	13.34	488375	4609318
#1 COKE BATTERY PUSHING	187.54	20.12	0.76	4.3	323	9.44	488045	4608362
#1 COKE BATTERY UNDERFIRE	187.15	76.81	3.78	80.2	547	7.15	487968	4608346
#2 COKE BATTERY PUSHING	187.15	26.82	2.44	94.4	335	20.20	488059	4608115
#2 COKE BATTERY UNDERFIRE	187.14	75.90	4.18	63.4	505	4.48	487959	4608191
SINTER WINDBOX STACK*	187.15	24.08	2.39	247.2	319	55.12	488038	4609329
BLAST FCE D CASTHOUSE/FUG	187.14	18.90	1.56	47.2	533	24.70	488203	4609371
BLAST FURNACE C STOVES	187.15	61.26	3.48	151.1	519	15.89	488244	4609339
BLAST FURNACE D STOVES	187.14	61.26	3.59	151.1	519	14.93	488229	4609496
BLAST FCE C CASTHOUSE/FUG	187.14	18.90	1.56	47.2	533	24.70	488203	4609371
STEELMAKING HMD STATION #1	187.14	25.91	2.05	42.7	305	12.95	488512	4609936
STEELMAKING HMD STATION #2	187.14	25.91	3.04	42.7	305	5.89	488542	4609936
STEELMAKING VESSELS #1 & #2	187.15	24.99	6.02	160.7	325	5.65	488544	4609957
STEELMAKING VESSEL #3	187.15	11.58	6.71	93.4	332	2.64	488555	4610037
STEELMAKING FM BOILER	187.15	67.66	1.99	5.6	478	1.79	488690	4609918
HOT STRIP FURNACE #1	187.14	41.45	4.30	402.5	811	7.06	489030	4609212
HOT STRIP FURNACE #3	187.14	41.45	3.97	109.0	811	8.81	489063	4609212
HOT STRIP FURNACE #2	187.14	41.45	4.30	102.0	811	7.02	489046	4609212
160" PLATE MILL FURNACE #1	187.14	54.25	3.10	33.0	673	4.37	489014	4609043
160" PLATE MILL FURNACE #2	187.14	54.25	3.10	33.0	693	4.09	489035	4609043
160" PLATE MILL FURNACE #5	187.14	39.92	1.95	37.3	783	12.48	489054	4609039
160" PLATE MILL FURNACES 6 & 7	187.14	32.92	2.24	39.3	783	9.99	489042	4608914
160" PLATE MILL FURNACE #8	187.14	50.90	1.74	7.1	673	2.99	489042	4608894
110 PLATE MILL FURNACES 1 & 2	187.14	54.56	4.44	33.0	838	2.13	489030	4608811
STEELMAKING HMD STATION #3	187.14	25.91	2.05	42.7	305	12.95	488601	4609962
110" Plate Mill Normalizing Fce	187.14	45.72	1.92	12.4	505	4.27	489801	4608431

Table 2-3 Burns Harbor Facility Baseline Emission Rates - Plant-wide Maximum Emission Day

Stack Description[(2)]	Peak 24-Hour Emissions (g/s)	
	SO_2	NO_X
POWER STATION Boiler Nos 7-12	218.31	162.49
#1 COKE BATTERY PUSHING	1.38	0.25
#1 COKE BATTERY UNDERFIRE	61.34	81.30
#2 COKE BATTERY PUSHING	1.39	0.25
#2 COKE BATTERY UNDERFIRE	64.26	4.65
SINTER WINDBOX STACK*	25.20	37.31
BLAST FCE D CASTHOUSE/FUG	0.00	1.02
BLAST FURNACE C STOVES	29.20	3.44
BLAST FURNACE D STOVES	32.28	3.28
BLAST FCE C CASTHOUSE/FUG	0.00	0.99
STEELMAKING HMD STATION #1	0.30	0.02
STEELMAKING HMD STATION #2	0.30	0.02
STEELMAKING VESSELS #1 & #2	0.15	2.54
STEELMAKING VESSEL #3	0.08	1.53
STEELMAKING FM BOILER	0.00	0.43
HOT STRIP FURNACE #1	4.23	5.97
HOT STRIP FURNACE #3	0.00	6.09
HOT STRIP FURNACE #2	4.29	6.14
160" PLATE MILL FURNACE #1	3.23	1.89
160" PLATE MILL FURNACE #2	3.31	1.83
160" PLATE MILL FURNACE #5	0.00	0.00
160" PLATE MILL FURNACES 6 & 7	0.00	0.00
160" PLATE MILL FURNACE #8	0.00	0.00
110 PLATE MILL FURNACES 1 &2	0.00	0.00
STEELMAKING HMD STATION #3	0.26	0.02
110" Plate Mill Normalizing Fce	0.00	0.00

Volume Source Description[(1)]	Model Inputs (g/s)	
	SO_2	NO_x
Blast Furnace C Slag Pit	3.28	0.00
Blast Furnace D Slag Pit	2.85	0.00
Steelmaking Fugitives	0.37	0.99

(1) Total emission from the volume sources were added to the Power Station Source when modeled. Production data frequency is monthly for all volume sources

(2) Fuel use and production data record frequency is same as that shown in Table 2-1.

Table 2-4 Combustion Unit Emission Factors Used In Emissions Calculations

Sulfur Dioxide

Fuel	Emission Units	SO_2 Emission Factor (lb/MMBTU)	Source of Emission Factor
Blast Furnace Gas	All Units	0.13	Based on stack test used as basis for annual emission fees reporting
Coke Oven Gas		Varies from 1.088 to 1.395	Semi-annual testing of No. 2 Coke Battery Underfiring Stack when combusting coke oven gas
Natural Gas		0.0006	AP-42, External Combustion

Oxides of Nitrogen

Fuel	Emission Units	NOx Emission Factor (lb/MMBTU)	Source of Emission Factor
Blast Furnace Gas	All Units Except Coke Battery Underfiring and Hot Strip Mill Reheat Furnaces	0.0100	ISG Indiana Harbor test of No. 7 Boiler Stack on 5/11/04
Coke Oven Gas		0.1367	FIRE database [SCC 10200707]
Natural Gas		0.1373	AP-42, External Combustion, Table 1.4-1, Low-NOx Burners. Converted from lb/MMscf using 1020 BTU/scf.
Fuel	**Emission Units**	**NOx Emission Factor (lb/MMcf)**	**Source of Emission Factor**
Blast Furnace Gas	No. 1 Coke Battery Underfiring	168.50	Average of 1995 & 2000 Burns Harbor Stack Tests
Coke Oven Gas		987	Average of 1995 & 2000 Burns Harbor Stack Tests
Natural Gas		NA	NA
Blast Furnace Gas	No. 2 Coke Battery Underfiring	NA	NA
Coke Oven Gas		60.57	2000 Burns Harbor Stack Test
Natural Gas		NA	NA
Coke Oven Gas	Hot Strip Mill Reheat Fce. Nos. 1 ,2 & 3	82.07	2/14/06 Burns Harbor Stack Test
Natural Gas		143.14	

Table 2-5 Process Unit Emission Factors Used In Emissions Calculations

Source	Pollutant	Emission Factor Uncontrolled	Units	Capture Efficiency (Control Device)	Control Efficiency (Control Device)	Controlled Emission Factor (lb/unit)	Source of Emission Factor
HMD Station Nos. 1, 2 & 3 Baghouse Stack Emissions	NOx	0.00100	lbs/ton HM	98.00%	0.00%	0.00098	BH Test Data (HMD/transfer/skimming) 8/13/02 Stack Test @ #2 HMD
	SO2	0.01400	lbs/ton HM	98.00%	0.00%	0.01372	BH Test Data (HMD/transfer/skimming) 8/13/02 Stack Test @ #2 HMD
BOF Nos. 1 & 2 (refining/blow) Stack Primary Emissions	NOx	0.05400	lbs/ton steel	99.80%	0.00%	0.05389	BH Test 9/29/93-10/14/93
	SO2	0.00604	lbs/ton steel	99.80%	50.00%	0.00302	BH 4/7/05 Test
BOF No. 3 (refining/blow) Stack Primary Emissions	NOx	0.05400	lbs/ton steel	99.99%	0.00%	0.05399	BH Test 9/29/93-10/14/93
	SO2	0.00604	lbs/ton steel	99.99%	50.00%	0.00302	BH 4/7/05 Test
Ladle Treatment Station (LTS) Nos. 4 & 5 BH Stack Emissions	NOx	0.00300	lbs/ton steel	99.99%	0.00%	0.00300	ArcelorMittal Indiana Harbor f/k/a Inland 2001 Emission Inv 2BOF Ladle Metallurgy
	SO2	0.02500	lbs/ton steel	99.99%	0.00%	0.02500	ArcelorMittal Indiana Harbor f/k/a Inland 2001 Emission Inv 2BOF Ladle Metallurgy
Steel Ladle Desulf Station Nos. 2 & 3 BH Stack Emissions	SO2	0.00245	lbs/ton steel	90.00%	0.00%	0.00221	Same SO2 emitted/steel sulfur conc. as HMD
Vacuum Degasser Process Flare Stack Emissions	NOx	0.00015	lbs/ton steel	100.00%	0.00%	0.00015	USS Gary Works 1998 Application for RH Vacuum Degasser
Coke Battery No. 1 Pushing	NOx	N/A	lbs/ton coal	N/A	N/A	0.01900	AP-42 Table 12.2-9
	SO2	N/A	lbs/ton coal	N/A	N/A	0.09800	AP-42 Table 12.2-9
Coke Battery No. 2 Pushing	NOx	N/A	lbs/ton coal	N/A	N/A	0.01900	AP-42 Table 12.2-9
	SO2	N/A	lbs/ton coal	N/A	N/A	0.09800	AP-42 Table 12.2-9
BF C Slag Pit	SO2	0.08500	lbs/ton HM	100.00%	0.00%	0.08500	USS Gary Works and Mittal Indiana Harbor West SIP Model
BF D Slag Pit	SO2	0.08500	lbs/ton HM	100.00%	0.00%	0.08500	USS Gary Works and Mittal Indiana Harbor West SIP Model
Sinter Plant Windbox	NOx	N/A	lbs/ton sinter	N/A	N/A	0.66700	BH 1/8/97 Test
	SO2	N/A	lbs/hr	N/A	N/A	200	Engineering Estimate based on stack sampling in 2008*

* Engineering evaluation in 2008 confirmed that Sinter Plant Windbox Scrubber properly operated sustained SO2 emissions below 200 lb./ ton.

3.0 Meteorological Data

This section discusses refinements to Lake Michigan Air Directors Consortium (LADCO) and Midwest Regional Planning Organization (MWRPO) meteorological database that were used for the Burns Harbor facility BART modeling.

3.1 Elements of the Refined Analysis

ENSR refined the CALMET meteorological data produced by LADCO/MWRPO for BART CALPUFF analyses for Midwestern States. The CALMET database derived by LADCO/MWRPO has a domain that covers approximately a 3,492 km (east-west) by 3,240 km (north-south) area with a 36-km grid resolution. This area covers the entire continental United States east of the Rocky Mountains, but its large size limits the horizontal resolution of each grid element to 36 km. This coarse grid resolution can be deemed appropriate for a screening-level analysis, but it would not be considered appropriate for a more refined analysis.

ENSR developed a refined meteorological database that would include a modeling domain encompassing the four Class I areas (Seney, Mingo, Mammoth, and Isle Royale), the Burns Harbor facility, and the appropriate buffers around the source and Class I areas for puffs recirculation. This domain covers approximately a 1,002 km (east-west) by 1,374 km (north-south) area, has a grid resolution of 6 km (6 times more resolved than the LADCO/MWRPO database in both east-west and north-south directions), and contains 10 vertical levels. The refined database utilizes the same MM5 databases that were used to develop the LADCO/MWRPO 36-km CALMET database.

In addition to the use of consistent MM5 databases with the LADCO-developed meteorological data, ENSR utilized similar model switches/settings, when appropriate, that were used to develop the LADCO/MWRPO CALMET database. To improve the database even further, ENSR introduced actual surface, precipitation, and twice-daily upper air sounding observations into the refined meteorological database. These improvements in the CALMET database provide more accurate plume trajectories from the Burns Harbor facility to the distant Class I areas.

In addition, ENSR used the latest EPA-approved versions of CALMET (Version 5.8) and CALPUFF (Version 5.8), rather than the "old" EPA-approved versions suggested in the MWRPO BART common protocol (available at http://www.state.in.us/idem/programs/air/workgroups/regionalhaze/docs/BART_protocol.pdf).

3.2 CALMET Processing

ENSR used refined 6-km grid spacing for the CALMET and CALPUFF models. The modeling domain was based on a 100 km buffer around the source and a 50 km buffer around each of the four Class I areas plus an additional buffer to the east and to the west to account for puffs recirculation. The modeling domain is shown in Figure 3-1. This design allows for a 1,002 km (east-west) x 1,374 km (north-south) domain extent and, at a 6-km resolution, there are 167 x 229 horizontal grid cells.

Due to the size of the modeling domain, a Lambert Conformal Conic (LCC) coordinate system was used to account for the curvature of the Earth's surface. The LCC projection for this analysis was based on the NAS-C datum and standard parallels of 33 and 45 degrees North, with an origin of 40 degrees North and 97 degrees West.

ENSR used the latest EPA-approved version of CALMET (Version 5.8, Level 070623) to produce three-dimensional wind fields for three years (2002-2004). Advanced meteorological data in the form of prognostic mesoscale meteorological data, such as the Fifth Generation Mesoscale Model (MM5), were used to provide a superior estimate of the initial wind fields. This application considered 3 years (2002-2004) of prognostic MM5 meteorological data at a 36-km resolution.

- 2002 MM5 data set at 36 km resolution provided by CENRAP;
- 2003 MM5 data set at 36 km resolution provided by Midwest RPO;
- 2004 MM5 data set at 36 km resolution provided by Midwest RPO.

These databases are consistent with those used by LADCO/MWRPO for their BART assessments.

These prognostic meteorological data sets were combined with the 6-km grid resolution terrain and land use data to more accurately characterize the wind flow throughout the modeling domain. The gridded terrain data was derived using several data sources because the modeling domain extends into Canadian territory. The U.S. Geological Survey (USGS) 90-meter grid spacing Digital Elevation Model (DEM) files were combined with the 100-meter grid spacing Canadian DEM files and the 90-meter spacing Shuttle RADAR Topo Mission files. These files were processed in the TERREL pre-processor program. The gridded land use data was derived from USGS 1:250,000 Composite Theme Grid land use files.

The Step 2 wind fields were produced using the input of all available National Weather Service (NWS) hourly surface and twice-daily upper air balloon sounding data within and just outside the modeling domain. Hourly surface data from both first-order and second-order stations also were considered in this analysis. Other sources of meteorological data such as CASTNET data and buoy stations were used to supplement areas lacking NWS or second-order data. Hourly precipitation data from stations within and just outside of the modeling domain were taken from a National Climatic Data Center data set. Figure 3-2 shows the meteorological stations that were used in the CALMET modeling and Appendix A provides their names and locations.

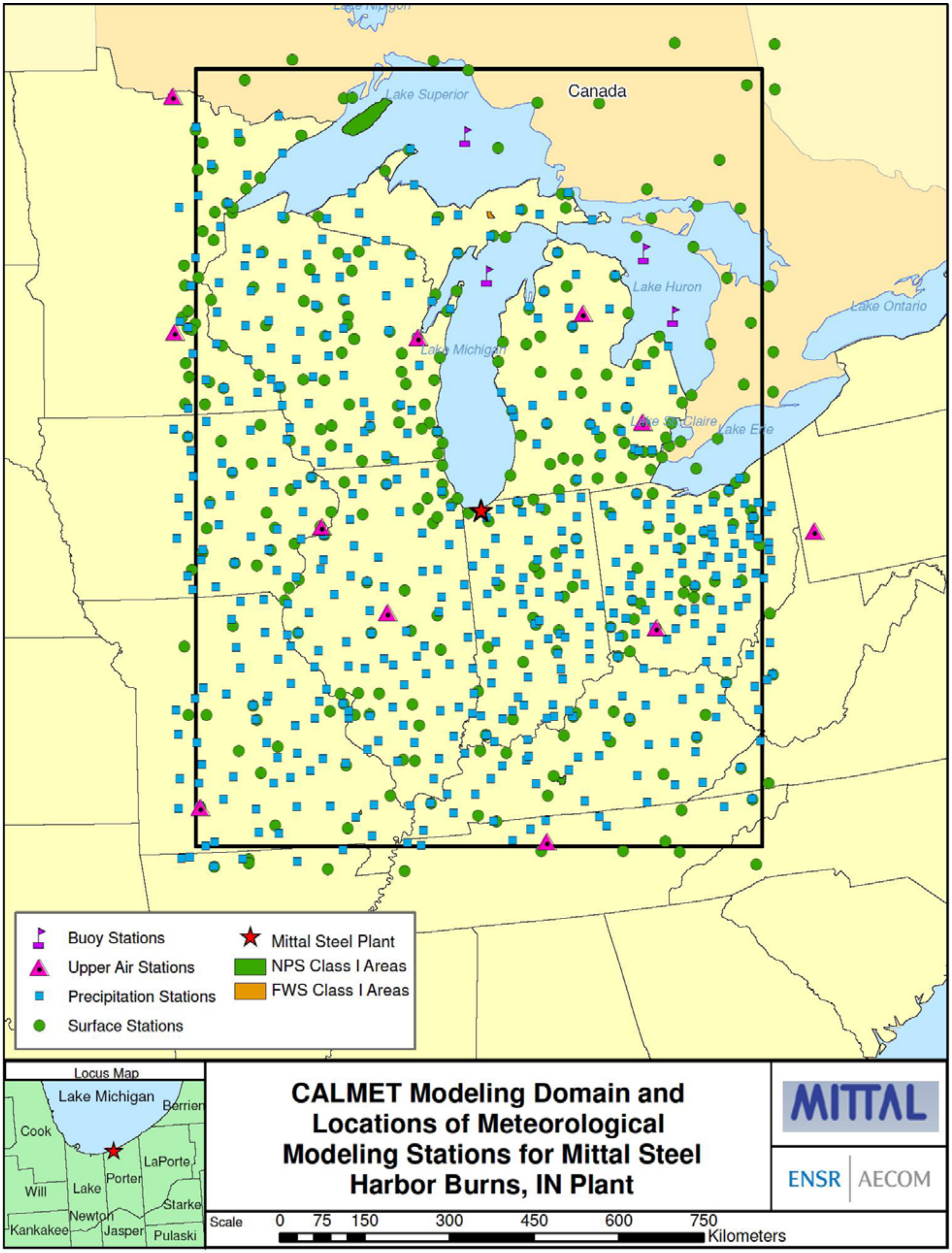
The non-default user-defined settings proposed for the CALMET processing are provided in Table 3-1.

Table 3-1 CALMET User-Defined Fields Not Specified in IWAQM Appendix A

Variable	Description	Value
NX	Number of east-west grid cells	167
NY	Number of north-south grid cells	229
DGRIDKM	Meteorology grid spacing (km)	6.0
NZ	Number of Vertical layers of input meteorology	10
ZFACE	Vertical cell face heights (m)	0.,20.,40.,80.,160.,300.,600.,1000.,1500.,2000.,3500.
RMAX1	Max surface over-land extrapolation radius (km)	40
RMAX2	Max aloft over-land extrapolation radius (km)	40
RMAX3	Maximum over-water extrapolation radius (km)	100
TERRAD	Radius of influence of terrain features (km)	15
R1	Relative weight at surface of Step 1 field and obs	5
R2	Relative weight aloft of Step 1 field and obs	5
IUPT	Station for lapse rates	International Falls, MN
IPROG	Gridded initial prognostic wind field – MM4/MM5 data	14

Figure 3-1 Burns Harbor CALMET and CALPUFF Modeling Domain

Figure 3-2 Location of Meteorological Stations used in CALMET Processing



4.0 CALPUFF Modeling

This section provides a summary of the modeling procedures that were used for the refined CALPUFF analysis conducted for the Burns Harbor facility.

4.1 CALPUFF Modeling Domain and Receptors

ENSR used the latest EPA-approved version of CALPUFF (Version 5.8, Level 070623) that has been posted at http://www.src.com/calpuff/download/download.htm#EPA_VERSION.

The extent of the CALMET/CALPUFF modeling domain are shown in Figure 3-1. The modeling domain included a 100 km buffer around the source and a 50 km buffer around each of the four Class I areas plus an additional buffer to the east and to the west to account for puffs recirculation. This design allows the modeling domain to extend 1,002 km east-west and 1,374 km north-south and have a 6-km grid element size.

The receptors for each of the Class I areas were based on the National Park Service database of Class I receptors.

4.2 Technical Options Used in the Modeling

For CALPUFF model technical options, inputs and processing steps, Burns Harbor followed the MWRPO common BART protocol.

For CALPUFF modeling, ENSR used seasonal ozone and ammonia ambient background concentrations that are consistent with the MWRPO common BART modeling protocol. For convenience, there values are listed in Table 4-1.

Table 4-1 MWRPO Ozone and Ammonia Seasonal Concentrations

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
O_3 (ppb)	31	31	31	37	37	37	33	33	33	27	27	27
NH_3 (ppb)	.3	.3	.3	.5	.5	.5	.5	.5	.5	.5	.5	.5

Due to the large distance to the nearest Class I area, building downwash effects were not included in the CALPUFF modeling.

4.3 Natural Conditions and Monthly f(RH) at Class I Areas

There are four Class I areas to be modeled for the Burns Harbor facility. For these Class I areas, natural background conditions must be established in order to determine a change in natural conditions related to a source's emissions.

For BART analyses, EPA has chosen to accept either the annual average or 20% best day's natural background for BART exemption and determination modeling analyses. Regional Planning Organization(s) (RPOs) have provided guidance to states within their RPOs on what values to accept, which typically has varied based on the degree of the meteorological database refinement. Since MWRPO uses the 36-km database with no observations, as a measure of conservatism, MWRPO/LADCO recommended to states that the 20% best day's background be incorporated into the analysis as opposed to the annual average. This conservative approach compensated for the inaccuracy of the 36-km meteorological data in no-obs mode.

Model refinements to improve accuracy reduce the need for conservative background assumptions. For instance, Wisconsin, a MWRPO state, has stated that they would allow sources to use the annual average background with the 98th percentile day as opposed to the 20% best days if a site-specific meteorological database is developed.

In addition, states within the VISTAS RPO* have uniformly decided to allow sources to use the annual average background coupled with the 98th percentile day when refined meteorological data (that incorporates observations) is used as input to the BART CALPUFF runs. This procedure was approved by EPA Region 4. To conduct the BART modeling, VISTAS, like the MWRPO, developed its own coarse no-obs 12-km resolution CALMET meteorological database covering all VISTAS states and Class I areas within 300 km. The 12-km CALMET meteorological data was used in the modeling analyses as a screening step to exempt BART eligible sources that, based on modeling, did not cause or contribute to visibility impairment (i.e. according to the BART rule did not have impacts greater than 0.5 dv).VISTAS also developed a more refined 4-km resolution CALMET databases that covered a sub-set of the large 12-km grid. These databases were able to be used in refined BART modeling analyses along with the annual average background. To ENSR's knowledge, all VISTAS states have accepted the use of the annual average background.

Burns Harbor used refined meteorological database with a finer grid resolution (6-km) and introduced surface observations. In addition, ENSR used the annual average background while evaluating BART exemption based on the source's impacts at the 98th percentile day. This procedure is consistent with the modeling approach taken by other eastern states and consistent with Wisconsin's approach within the MWRPO.

For the modeling described in this document, ENSR used the annual average natural background concentrations shown in Table 4-2, modified as noted below with site-specific considerations (as shown in Table 4-3), and corresponding to the annual average natural background concentrations (EPA 2003, Appendix B).

To determine the input to CALPOST, it is first necessary to convert the deciviews to extinction using the equation:

Extinction (Mm^{-1}) = 10 exp(deciviews/10).

For example, for Mingo, 7.43 deciviews is equivalent to an extinction of 21.02 inverse megameters (Mm^{-1}); this extinction includes the default 10 Mm-1 for Rayleigh scattering. This remaining extinction is due to naturally occurring particles, and is held constant for the entire year's simulation. Therefore, the data provided to CALPOST for Mingo would be the total natural background extinction minus 10 (expressed in Mm^{-1}), or 11.02. This is most easily input as a fine soil concentration of 11.02 $\mu g/m^3$ in CALPOST, since the extinction efficiency of soil (PM-fine) is 1.0 and there is no f(RH) component. The concentration entries for all other particle constituents would be set to zero, and the fine soil concentration would be kept the same for each month of the year. The monthly values for f(RH) that CALPOST needs were taken from "Guidance for Tracking Progress Under the Regional Haze Rule" (EPA, 2003) Appendix A, Table A-3.

* The VISTAS states include: Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee, Virginia, and West Virginia.

Table 4-2 Annual Average Natural Background Concentrations

Component Represented	Isle Royale	Mammoth Cave	Mingo	Seney
Soil (PM fine) (deciview)	7.38	7.69	7.43	7.53
Soil (PM fine) (Mm^{-1} or $\mu g/m^3$)	20.92	21.58	21.02	21.23

* Extinction values include Rayleigh scattering.

Table 4-3 New IMPROVE Equation Background Sea Salt Concentration and Site-specific Rayleigh Scattering Coefficient

Parameter	Isle Royale	Mammoth Cave	Mingo	Seney
Sea Salt Concentration ($\mu g/m^3$)	0.03	0.02	0.01	0.02
Rayleigh Scattering Coefficient (Mm-1)	12	11	12	12

Note: Data taken from VIEWS website (http://vista.cira.colostate.edu/views/)

4.4 Light Extinction and Haze Impact Calculations

The CALPOST postprocessor was used for the calculation of the impact from the modeled source's primary and secondary particulate matter concentrations on light extinction. The formula that is used is the existing IMPROVE/EPA formula, which is applied to determine a change in light extinction due to increases in the particulate matter component concentrations. Using the notation of CALPOST, the formula is the following:

$$b_{ext} = 3\ f(RH)\ [(NH_4)_2SO_4] + 3\ f(RH)\ [NH_4NO_3] + 4[OC] + 1[Soil] + 0.6[Coarse\ Mass] + 10[EC] + b_{Ray}$$

The concentrations, in square brackets, are in $\mu g/m^3$ and b_{ext} is in units of Mm^{-1}. The Rayleigh scattering term (b_{Ray}) has a default value of 10 Mm^{-1}, as recommended in EPA guidance for tracking reasonable progress (EPA, 2003a).

Dr. Ivar Tombach, consultant to VISTAS, has provided a spreadsheet calculation system (see Appendix B) that incorporates the revised IMPROVE equation (also documented in Appendix B) for determining light extinction from particulate concentration estimates. We used this approach instead of the old/current IMPROVE equation in the presentation of the BART modeling. The Fish & Wildlife Service, who administer the Seney and Mingo Wilderness Areas, have previously communicated to ENSR (2006) that they approve of Dr. Tombach's procedure for implementing the new IMPROVE equation, and that this equation may be used for regional haze assessments with this approach. Notably, the Federal Land Managers associated with the US Fish and Wildlife Service recently approved the use of the new IMPROVE equation at Seney Wilderness (as implemented here using Dr. Tombach's procedures) for a PSD permit application in Michigan.

The new IMPROVE equation is fundamentally different in 3 major areas (taken from Ivar Tombach's *"Instructions: A Postprocessor for Recalculating CALPOST Visibility Outputs with the New IMPROVE Algorithm"*):

(1) 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.

(2) The contribution of fine sea salt to light extinction has been added, and is accompanied by its own hygroscopic scattering enhancement factor, fss(RH).

(3) 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.

States and other RPOs have allowed sources to use the new IMPROVE equation as opposed to the IMPROVE equation algorithms that are currently coded into CALPOST because these differences (noted above) represent a real improvement over how the old/current IMPROVE equation calculates light extinction. ENSR used the new IMPROVE equation for the light extinction calculations in this refined BART analysis using the guidance provided by Dr. Ivar Tombach. Table 4-3 lists sea salt concentrations and Rayleigh coefficients that were used as input to the new IMPROVE equation.

In addition to using the new IMPROVE equation, the assessment of visibility impacts at the Class I areas used CALPOST Method 6 (as standard with all BART applications). Each hour's source-caused extinction is calculated by first using the hygroscopic components of the source-caused concentrations, due to ammonium sulfate and nitrate, and monthly Class I area-specific f(RH) values. The contribution to the total source-caused extinction from ammonium sulfate and nitrate is then added to the other, non-hygroscopic components of the particulate concentration (from coarse and fine soil, secondary organic aerosols, and from elemental carbon) to yield the total hourly source-caused extinction.

5.0 Modeling Results

The BART exemption modeling results at the four Class I areas using the maximum emissions by emission unit are provided in Table 5-1. Table 5-2 provides the results of the more realistic modeling using the maximum plant-wide emission days. Both tables indicate that the 8th highest day's impacts for each year are below the 0.5 delta-deciviews threshold. These results demonstrate that the ArcelorMittal Burns Harbor emissions do not cause or contribute to regional haze in any of these four Class I area. Therefore, Burns Harbor facility is not subject to BART and no further BART analysis is required.

Table 5-1 BART Exemption Modeling Results - Maximum by Emission Unit

Class I Area	2002				2003				2004			
	Days > than		MAX Δ dv	8th Highest Δ dv$_t$	Days > than		MAX Δ dv	8th Highest Δ dv	Days > than		MAX Δ dv	8th Highest Δ dv$_t$
	0.5 Δ dv	1.0 Δ dv			0.5 D dv	1.0 D dv			0.5 D dv	1.0 D dv		
MVISBK=6, Annual Average Background, 6-km CALMET, New IMPROVE Equation												
Isle Royale National Park	0	0	0.220	0.083	2	0	0.601	0.117	2	0	0.615	0.163
Mammoth Cave National Park	2	0	0.898	0.351	3	0	0.674	0.333	1	0	0.658	0.218
Mingo Wilderness	3	0	0.705	0.199	1	0	0.559	0.224	0	0	0.414	0.181
Seney Wilderness	4	0	0.750	0.346	4	1	1.165	0.375	7	1	1.030	0.464

Table 5-2 BART Exemption Modeling Results - Plant-wide Maximum Emission Day

Class I Area	2002				2003				2004			
	Days > than		MAX Δ dv	8th Highest Δ dv$_t$	Days > than		MAX Δ dv	8th Highest Δ dv	Days > than		MAX Δ dv	8th Highest Δ dv$_t$
	0.5 Δ dv	1.0 Δ dv			0.5 D dv	1.0 D dv			0.5 D dv	1.0 D dv		
MVISBK=6, Annual Average Background, 6-km CALMET, New IMPROVE Equation												
Isle Royale National Park	0	0	0.188	0.069	2	0	0.533	0.099	2	0	0.542	0.143
Mammoth Cave National Park	2	0	0.789	0.300	2	0	0.574	0.287	1	0	0.563	0.185
Mingo Wilderness	2	0	0.629	0.170	0	0	0.474	0.189	0	0	0.352	0.155
Seney Wilderness	2	0	0.675	0.297	2	0	1.027	0.332	6	0	0.914	0.405

6.0 References

ENSR, Personal communication to Mr. Robert Paine from Mr. Tim Allen of the U.S Fish and Wildlife Service

Environmental Protection Agency (EPA), AP 42, Fifth Edition, Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources, January, 1995

Environmental Protection Agency (EPA), Guidance for Tracking Progress Under the Regional Haze Rule, EPA-454/B-03-003, Appendix A, Table A-3, September, 2003a

Environmental Protection Agency (EPA), Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program, EPA 454/B-03-005, September 2003b

Environmental Protection Agency (EPA), Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts, EPA-454/R-98-019, December, 1998

Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule (FR Vol. 70, No. 128 published July 6, 2005)

Regional Haze Regulations; Revisions to Provisions Governing Alternative to Source-Specific Best Available Retrofit Technology (BART) Determinations; Final Rule (FR Vol. 71, NO. 198 published October 13, 2006)

Single Source Modeling to Support Regional Haze BART Modeling Protocol November 17, 2005, Lake Michigan Air Directors Consortium, Des Plaines, IL

Appendix A

Meteorological Stations used in CALMET Processing

Table A-1 Surface Stations used in CALMET Processing

Country/State	WBAN ID	Source [1]	Name	Latitude	Longitude	Elevation (m)	2002	2003	2004
Canada	712600	NNDC	SAULT STE MARIE	46.48	-84.51	192	x	x	x
Canada	712610	NNDC	GODERICH (AUTO8)	43.76	-81.71	214	x	x	x
Canada	712700	NNDC	COLLINGWOOD (AUT8)	44.50	-80.21	180	x	x	x
Canada	712730	NNDC	BELLE RIVER	42.30	-82.70	184	x	x	x
Canada	713680	NNDC	WATERLOO WELL	43.46	-80.38	317	x	x	x
Canada	714330	NCDC	CARIBOU ISL (MAPS)	47.33	-85.83	187	x	x	x
Canada	714350	NCDC	UPSALA (MARS)	49.03	-90.46	489	x	x	x
Canada	714390	NCDC	COVE ISLAND (MAPS)	45.33	-81.73	181	x	x	x
Canada	714600	NCDC	KILLARNEY (MAPS)	45.96	-81.48	196	x	x	x
Canada	714620	NCDC	GREAT DUCK ISLAND	45.63	-82.96	183	x	x	x
Canada	714650	NCDC	ERIEAU (MAPS)	42.25	-81.90	178	x	x	x
Canada	714660	NCDC	S.E. SHOAL (MAPS)	41.83	-82.46	195	x	x	x
Canada	715380	NCDC	WINDSOR AIRPORT	42.26	-82.96	190	x	x	x
Canada	715730	NCDC	DELHI CS	42.83	-80.55	232	x	x	x
Canada	716230	NCDC	LONDON AIRPORT	43.03	-81.15	278	x	x	x
Canada	716310	NCDC	MOUNT FOREST(MARS)	43.98	-80.75	415	x	x	x
Canada	716330	NCDC	WIARTON AIRPORT	44.75	-81.10	222	x	x	x
Canada	716340	NCDC	SARNIA AIRPORT	43.00	-82.31	181	x	x	x
Canada	716420	NCDC	CHAPLEAU A	47.81	-83.35	447	x	x	x
Canada	717300	NCDC	SUDBURY AIRPORT	46.61	-80.80	348	x	x	x
Canada	717320	NCDC	BRITT (MARS)	45.80	-80.53	192	x	x	x
Canada	717330	NCDC	GORE BAY AIRPORT	45.88	-82.56	193	x	x	x
Canada	717334	NCDC	ELLIOT LAKE (SAWR)	46.35	-82.56	329	x	x	x
Canada	717340	NCDC	ROUYN	48.25	-79.03	318	x	x	x
Canada	717350	NCDC	EARLTON AIRPORT	47.70	-79.85	243	x	x	x
Canada	717380	NCDC	WAWA AIRPORT	47.96	-84.78	287	x	x	x
Canada	717390	NCDC	TIMMINS AIRPORT	48.56	-81.36	295	x	x	x
Canada	717470	NCDC	ATIKOKAN	48.76	-91.63	389	x	x	x
Canada	717490	NCDC	THUNDER BAY AIRPORT	48.36	-89.31	199	x	x	x
Canada	717493	NCDC	TERRACE BAY (SAWR)	48.81	-87.10	287	x	x	x
Canada	717500	NCDC	PUKASKWA	48.60	-86.30	206	x	x	x
Canada	717510	NCDC	WELCOME ISLAND	48.36	-89.11	209	x	x	x
Canada	718200	NCDC	BARRAGE ANGLIERS	47.55	-79.23	266	x	x	x
AR	723406	NCDC	WALNUT RIDGE (AWOS)	36.13	-90.91	83	x	x	x
AR	723439	NCDC	BAXTER CO RGNL APT	36.36	-92.46	283	x	x	x
AR	723446	NCDC	HARRISON FAA AP	36.26	-93.15	418	x	x	x
AR	723447	NCDC	FLIPPIN (AWOS)	36.30	-92.46	350	x	x	x
IA	725349	NCDC	DAVENPORT NEXRAD	41.61	-90.58	259	x	x	x
IA	725450	NCDC	CEDAR RAPIDS MUNICI	41.88	-91.71	256	x	x	x
IA	725454	NCDC	WASHINGTON	41.28	-91.66	230	x	x	x
IA	725455	NCDC	BURLINGTON MUNICIPA	40.78	-91.11	210	x	x	x
IA	725456	NCDC	KEOKUK MUNI	40.46	-91.43	205	x	x	x
IA	725461	NCDC	MARSHALL TOWN MUNI	42.10	-92.91	296	x	x	x
IA	725462	NCDC	IOWA CITY MUNI	41.63	-91.55	198	x	x	x
IA	725463	NCDC	CHARLES CITY	43.06	-92.61	343	x	x	x
IA	725464	NCDC	NEWTON MUNI	41.68	-93.01	290	x	x	x
IA	725465	NCDC	OTTUMWA INDUSTRIAL	41.10	-92.45	256	x	x	x
IA	725469	NCDC	CHARITON	41.03	-93.36	320	x	x	x
IA	725470	NCDC	DUBUQUE REGIONAL AP	42.40	-90.70	321	x	x	x
IA	725473	NCDC	CLINTON MUNI (AWOS)	41.83	-90.33	216	x	x	x
IA	725475	NCDC	MONTICELLO MUNI	42.23	-91.16	259	x	x	x
IA	725476	NCDC	DECORAH	43.28	-91.73	353	x	x	x
IA	725480	NCDC	WATERLOO MUNICIPAL	42.55	-92.40	263	x	x	x
IA	725483	NCDC	FORT MADISON	40.66	-91.33	221	x	x	x
IA	725485	NCDC	MASON CITY MUNICIPA	43.15	-93.33	363	x	x	x
IA	725487	NCDC	MUSCATINE	41.36	-91.15	167	x	x	x
IA	725488	NCDC	OELWEN	42.68	-91.96	328	x	x	x
IA	725493	NCDC	KNOXVILLE	41.30	-93.11	283	x	x	x
IA	726498	NCDC	FAIR FIELD	41.05	-91.98	244	x	x	x
IL	724330	NCDC	SALEM-LECKRONE	38.65	-88.96	174	x	x	x
IL	724335	NCDC	MOUNT VERNON (AWOS)	38.31	-88.86	146	x	x	x
IL	724336	NCDC	CARBONDALE/MURPHYSB	37.78	-89.25	125	x	x	x
IL	724338	NCDC	BELLEVILLE SCOTT AF	38.55	-89.85	135	x	x	x
IL	724339	NCDC	MARION REGIONAL	37.75	-89.01	144	x	x	x
IL	724390	NCDC	SPRINGFIELD CAPITAL	39.85	-89.68	178	x	x	x
IL	724395	NCDC	ALTON/ST LOUIS RGNL	38.90	-90.05	166	x	x	x
IL	724396	NCDC	QUINCY MUNI BALDWIN	39.93	-91.20	232	x	x	x
IL	724397	NCDC	BLOOMINGTON/NORMAL	40.48	-88.91	267	x	x	x
IL	725300	NCDC	CHICAGO OHARE INTL	41.98	-87.91	200	x	x	x
IL	725305	NCDC	W. CHICAGO/DU PAGE	41.91	-88.25	231	x	x	x
IL	725314	NCDC	CAHOKIA/ST. LOUIS	38.56	-90.15	126	x	x	x
IL	725315	NCDC	CHAMPAIGN/URBANA	40.03	-88.28	230	x	x	x
IL	725316	NCDC	DECATUR AIRPORT	39.83	-88.86	208	x	x	x
IL	725317	NCDC	MATTOON/CHARLESTON	39.48	-88.28	220	x	x	x
IL	725320	NCDC	PEORIA GREATER PEOR	40.66	-89.68	198	x	x	x
IL	725326	NCDC	STERLING ROCKFALLS	41.75	-89.66	197	x	x	x

Table A-1 Surface Stations used in CALMET Processing

Country/State	WBAN ID	Source [1]	Name	Latitude	Longitude	Elevation (m)	2002	2003	2004
IL	724397	NCDC	BLOOMINGTON/NORMAL	40.48	-88.91	267	x	x	x
IL	725300	NCDC	CHICAGO OHARE INTL	41.98	-87.91	200	x	x	x
IL	725305	NCDC	W. CHICAGO/DU PAGE	41.91	-88.25	231	x	x	x
IL	725314	NCDC	CAHOKIA/ST. LOUIS	38.56	-90.15	126	x	x	x
IL	725315	NCDC	CHAMPAIGN/URBANA	40.03	-88.28	230	x	x	x
IL	725316	NCDC	DECATUR AIRPORT	39.83	-88.86	208	x	x	x
IL	725317	NCDC	MATTOON/CHARLESTON	39.48	-88.28	220	x	x	x
IL	725320	NCDC	PEORIA GREATER PEOR	40.66	-89.68	198	x	x	x
IL	725326	NCDC	STERLING ROCKFALLS	41.75	-89.66	197	x	x	x
IL	725340	NCDC	CHICAGO MIDWAY AP	41.78	-87.75	186	x	x	x
IL	725342	NCDC	LAWRENCEVILLE\VIN.	38.76	-87.60	131	x	x	x
IL	725345	NCDC	JOLIET PARK DISTRIC	41.51	-88.18	177	x	x	x
IL	725346	NCDC	CHICAGO MEIGS FIELD	41.86	-87.61	180	x	x	
IL	725347	NCDC	CHICAGO/WAUKEGAN	42.41	-87.86	222	x	x	x
IL	725348	NCDC	CHICAGO NEXRAD	41.60	-88.08	231	x	x	x
IL	725430	NCDC	ROCKFORD GREATER RO	42.20	-89.10	223	x	x	x
IL	725440	NCDC	MOLINE QUAD CITY IN	41.46	-90.51	180	x	x	x
IL	744655	NCDC	AURORA MUNICIPAL	41.76	-88.46	215	x	x	x
IL	744665	NCDC	CHICAGO/PALWAUKEE	42.11	-87.90	197		x	x
IL	ALH157	CASTNET	Alhambra	38.87	-89.62	164	x	x	x
IL	STK138	CASTNET	Stockton	42.29	-90.00	274	x	x	x
IN	724320	NCDC	EVANSVILLE REGIONAL	38.05	-87.53	116	x	x	x
IN	724356	NCDC	SHELBYVILLE MUNI	39.58	-85.80	245	x	x	x
IN	724363	NCDC	COLUMBUS BAKALAR	39.26	-85.90	199	x	x	x
IN	724365	NCDC	HUNTINGBURG	38.25	-86.95	161		x	x
IN	724373	NCDC	TERRE HAUTE HULMAN	39.45	-87.30	175	x	x	x
IN	724375	NCDC	BLOOMINGTON/MONROE	39.15	-86.61	258	x	x	x
IN	724380	NCDC	INDIANAPOLIS INTL A	39.71	-86.26	241	x	x	x
IN	724384	NCDC	EAGLE CREEK	39.83	-86.30	250	x	x	x
IN	724385	NCDC	ANDERSON MUNICIPAL	40.11	-85.61	280	x	x	x
IN	724386	NCDC	LAFAYETTE PURDUE UN	40.41	-86.93	182	x	x	x
IN	724387	NCDC	KOKOMO(AWOS)	40.53	-86.06	253		x	x
IN	724388	NCDC	GOSHEN	41.53	-85.78	252	x	x	x
IN	725327	NCDC	VALPARAISO	41.45	-87.00	234	x	x	x
IN	725330	NCDC	FORT WAYNE INTL AP	41.00	-85.20	241	x	x	x
IN	725335	NCDC	GRISSOM AFB/PERU	40.65	-86.15	247	x	x	x
IN	725336	NCDC	MUNCIE/JOHNSON FLD	40.25	-85.40	286	x	x	x
IN	725337	NCDC	GARY REGIONAL	41.61	-87.41	180	x	x	x
IN	725350	NCDC	SOUTH BEND MICHIANA	41.70	-86.33	235	x	x	x
IN	725354	NCDC	ELKHART MUNICIPAL	41.71	-86.00	237	x	x	x
IN	SAL133	CASTNET	Salamonie Reservoir	40.82	-85.66	250	x	x	x
KY	724210	NCDC	CINCINNATI NORTHERN	39.05	-84.66	264	x	x	x
KY	724220	NCDC	LEXINGTON BLUEGRASS	38.03	-84.60	294	x	x	x
KY	724230	NCDC	LOUISVILLE STANDIFO	38.18	-85.73	146	x	x	x
KY	724233	NCDC	CAPITAL CITY ARPT	38.18	-84.90	245	x	x	x
KY	724235	NCDC	LOUISVILLE BOWMAN F	38.23	-85.66	164	x	x	x
KY	724236	NCDC	JACKSON JULIAN CARR	37.58	-83.31	416	x	x	x
KY	724237	NCDC	OWENSBORO/DAVIESS	37.73	-87.16	124	x	x	x
KY	724238	NCDC	HENDERSON CITY	37.81	-87.68	117	x	x	x
KY	724240	NCDC	FORT KNOX GODMAN AA	37.90	-85.96	239	x	x	x
KY	724243	NCDC	LONDON-CORBIN AP	37.08	-84.08	362	x	x	x
KY	724350	NCDC	PADUCAH BARKLEY REG	37.05	-88.76	124	x	x	x
KY	724354	NCDC	SOMERSET(AWOS)	38.00	-84.60	283	x	x	x
KY	746710	NCDC	FORT CAMPBELL (AAF)	36.66	-87.50	173	x	x	x
KY	746716	NCDC	BOWLING GREEN WARRE	36.98	-86.43	160	x	x	x
KY	CDZ171	CASTNET	Cadiz	36.78	-87.85	189	x	x	x
KY	CKT136	CASTNET	Crockett	37.92	-83.07	455	x	x	x
KY	MCK131	CASTNET	Mackville	37.70	-85.05	353	x	x	x
KY	MAC426	CASTNET	Mammoth Cave	37.28	-86.26	236	x	x	x
MI	725370	NCDC	DETROIT METROPOLITA	42.21	-83.35	194	x	x	x
MI	725373	NCDC	GROSSE ISLE ARPT	42.10	-83.15	176	x	x	x
MI	725374	NCDC	ANN ARBOR MUNICIPAL	42.21	-83.75	256	x	x	x
MI	725375	NCDC	DETROIT CITY AIRPOR	42.40	-83.00	190	x	x	x
MI	725376	NCDC	DETROIT WILLOW RUN	42.23	-83.53	218	x	x	x
MI	725377	NCDC	MOUNT CLEMENS SELFR	42.61	-82.83	176	x	x	x
MI	725378	NCDC	HOWELL	42.63	-83.98	293	x	x	x
MI	725383	NCDC	STURGIS\KIRSH MUNI	41.81	-85.43	0	x	x	x
MI	725384	NCDC	ST.CLAIR COUNTY INT	42.91	-82.53	198	x	x	x
MI	725386	NCDC	HARBOR BEACH(RAMOS)	44.01	-82.80	183	x	x	x
MI	725387	NCDC	COPPER HARBOR RAMOS	47.45	-87.90	186	x	x	x
MI	725390	NCDC	LANSING CAPITAL CIT	42.78	-84.58	256	x	x	x
MI	725394	NCDC	HOLLAND/TULIP CITY	42.75	-86.10	210	x	x	x
MI	725395	NCDC	JACKSON REYNOLDS FI	42.26	-84.46	304	x	x	x

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Table A-1 Surface Stations used in CALMET Processing

Country/State	WBAN ID	Source [1]	Name	Latitude	Longitude	Elevation (m)	2002	2003	2004
MI	725396	NCDC	BATTLE CREEK	42.30	-85.25	282	x	x	x
MI	725404	NCDC	ADRIAN	41.86	-84.08	244	x	x	x
MI	725405	NCDC	ALMA	43.31	-84.68	230	x	x	x
MI	725406	NCDC	BAD AXE	43.78	-82.98	234	x	x	x
MI	725407	NCDC	GAYLORD	45.01	-84.68	404	x	x	x
MI	725408	NCDC	MANISTIQUE	45.96	-86.18	209	x	x	x
MI	725409	NCDC	HILLSDALE	41.91	-84.58	360	x	x	x
MI	725414	NCDC	COLDWATER	41.93	-85.05	292	x	x	x
MI	725415	NCDC	MARSHALL BROOKS	42.25	-84.95	287	x	x	x
MI	725416	NCDC	BIG RAPIDS	43.71	-85.50	302	x	x	x
MI	725417	NCDC	MASON	42.56	-84.41	280	x	x	x
MI	725418	NCDC	MONROE	41.93	-83.43	188	x	x	x
MI	725424	NCDC	MT PLEASANT MUNI	43.61	-84.73	230	x	x	x
MI	726284	NCDC	GWINN SAWYER AIRPO	46.35	-87.38	372	x	x	x
MI	726350	NCDC	GRAND RAPIDS KENT C	42.88	-85.51	241	x	x	x
MI	726355	NCDC	BENTON HARBOR/ROSS	42.13	-86.43	196	x	x	x
MI	726357	NCDC	KALAMAZOO INTL ARPT	42.23	-85.55	266	x	x	x
MI	726360	NCDC	MUSKEGON COUNTY ARP	43.16	-86.23	190	x	x	x
MI	726364	NCDC	LUDINGTON/MASON	43.96	-86.40	197	x	x	x
MI	726370	NCDC	FLINT BISHOP INTL A	42.96	-83.75	233	x	x	x
MI	726375	NCDC	PONTIAC-OAKLAND	42.66	-83.41	299	x	x	x
MI	726379	NCDC	SAGINAW TRI CITY IN	43.53	-84.08	201	x	x	x
MI	726380	NCDC	HOUGHTON LAKE ROSCO	44.36	-84.68	350	x	x	x
MI	726384	NCDC	CADILLAC WEXFORD CO	44.28	-85.41	396	x	x	x
MI	726385	NCDC	MANISTEE (AWOS)	44.26	-86.25	189	x	x	x
MI	726387	NCDC	TRAVERSE CITY CHERR	44.73	-85.58	188	x	x	x
MI	726390	NCDC	ALPENA COUNTY REGIO	45.06	-83.58	210	x	x	x
MI	726394	NCDC	NEWBERRY LUCE CO.	46.31	-85.46	198	x	x	x
MI	726395	NCDC	OSCODA WURTSMITH AF	44.45	-83.40	188	x	x	x
MI	726399	NCDC	SEUL CHOIX PT(AMOS)	45.91	-85.91	180	x	x	x
MI	726480	NCDC	ESCANABA (AWOS)	45.75	-87.03	187	x	x	x
MI	726487	NCDC	MENOMINEE (AWOS)	45.13	-87.63	191	x	x	x
MI	727340	NCDC	SAULT STE MARIE SAN	46.46	-84.35	218	x	x	x
MI	727344	NCDC	CHIPPEWA INTL(AWOS)	46.25	-84.46	244	x	x	x
MI	727347	NCDC	PELLSTON EMMET COUN	45.56	-84.78	217	x	x	x
MI	727435	NCDC	MACKINACK ISLAND	46.35	-87.40	372	x	x	x
MI	727436	NCDC	ANTRIM CO ARPT	44.98	-85.20	190	x	x	x
MI	727437	NCDC	IRON MOUNTAIN/FORD	45.81	-88.11	360	x	x	x
MI	727440	NCDC	HANCOCK HOUGHTON CO	47.16	-88.50	327	x	x	x
MI	727445	NCDC	IRONWOOD (AWOS)	46.53	-90.13	375	x	x	x
MI	727449	NCDC	MOOSE LAKE CO ARPT	46.41	-92.80	184	x	x	x
MI	ANA115	CASTNET	Ann Arbor	42.42	-83.90	267	x	x	x
MI	HOX148	CASTNET	Hoxyville	44.18	-85.74	305	x	x	x
MI	UVL124	CASTNET	Unionville	43.61	-83.36	201	x	x	x
MN	726440	NCDC	ROCHESTER INTERNATI	43.90	-92.50	397	x	x	x
MN	726544	NCDC	ORR	48.01	-92.86	397	x	x	x
MN	726549	NCDC	COOK MUNI ARPT	47.81	-92.70	402	x	x	x
MN	726558	NCDC	CLOQUET (AWOS)	46.70	-92.50	390	x	x	x
MN	726563	NCDC	FARIBAULT MUNI AWOS	44.33	-93.31	322	x	x	x
MN	726564	NCDC	RED WING	44.58	-92.48	239	x	x	x
MN	726568	NCDC	OWATONNA (AWOS)	44.11	-93.25	350	x	x	x
MN	726575	NCDC	MINNEAPOLIS/CRYSTAL	45.06	-93.35	265	x	x	x
MN	726577	NCDC	MINNEAPOLIS/BLAINE	45.15	-93.21	278	x	x	x
MN	726580	NCDC	MINNEAPOLIS-ST PAUL	44.88	-93.23	254	x	x	x
MN	726584	NCDC	SAINT PAUL DOWNTOWN	44.95	-93.06	219	x	x	x
MN	726588	NCDC	WINONA MUNI (AWOS)	44.08	-91.70	200	x	x	x
MN	726589	NCDC	ALBERT LEA (AWOS)	43.68	-93.36	383	x	x	x
MN	726596	NCDC	DODGE CENTER AIRPOR	44.01	-92.81	398	x	x	x
MN	726603	NCDC	SOUTH ST PAUL MUNI	44.85	-93.15	250	x	x	x
MN	726679	NCDC	RUSH CITY RGNL ARPT	45.68	-92.95	281	x	x	x
MN	727444	NCDC	TWO HARBORS	47.05	-91.75	328	x	x	x
MN	727450	NCDC	DULUTH INTERNATIONA	46.83	-92.21	433	x	x	x
MN	727454	NCDC	GRAND MARAIS MUNI	47.83	-90.38	505	x	x	x
MN	727455	NCDC	HIBBING CHISHOLM-HI	47.38	-92.85	410	x	x	x
MN	727456	NCDC	DULUTH HARBOR (CGS)	46.76	-92.08	186	x	x	x
MN	727459	NCDC	ELY MUNI (AWOS)	47.81	-91.83	443	x	x	x
MN	727469	NCDC	GRAND MARIAS	47.83	-90.38	186	x	x	x
MN	727473	NCDC	CRANE LAKE (AWOS)	46.26	-92.56	350	x	x	x
MN	727474	NCDC	EVELETH MUNI (AWOS)	47.40	-92.50	421	x	x	x
MN	727475	NCDC	MORA MUNI (AWOS)	45.88	-93.26	309	x	x	x
MN	727503	NCDC	CAMBRIDGE MUNI	45.56	-93.26	287	x	x	x
MN	727556	NCDC	SILVER BAY	47.20	-91.40	331	x	x	x
MN	727566	NCDC	AUSTIN MUNI	43.66	-92.93	375	x	x	x

Table A-1 Surface Stations used in CALMET Processing

Country/State	WBAN ID	Source [1]	Name	Latitude	Longitude	Elevation (m)	2002	2003	2004
MO	723300	NCDC	POPLAR BLUFF(AMOS)	36.76	-90.46	146	x	x	x
MO	723484	NCDC	WEST PLAINS - ASOS	36.88	-91.90	374	x	x	x
MO	723489	NCDC	CAPE GIRARDEAU MUNI	37.23	-89.56	102	x	x	x
MO	724340	NCDC	ST LOUIS LAMBERT IN	38.75	-90.36	173	x	x	x
MO	724345	NCDC	ST LOUIS SPIRIT OF	38.65	-90.65	140	x	x	x
MO	724347	NCDC	ST CHARLES COUNTY A	38.91	-90.41	133	x	x	x
MO	724400	NCDC	SPRINGFIELD REGIONA	37.23	-93.38	383	x	x	x
MO	724450	NCDC	COLUMBIA REGIONAL A	38.81	-92.21	272	x	x	x
MO	724453	NCDC	SEDALIA MEMORIAL	38.70	-93.18	277	x	x	x
MO	724454	NCDC	FARMINGTON	37.76	-90.40	274	x	x	x
MO	724455	NCDC	KIRKSVILLE REGIONAL	40.10	-92.55	294	x	x	x
MO	724456	NCDC	VICHY ROLLA NATL AR	38.13	-91.76	335	x	x	x
MO	724457	NCDC	FORT LEONARD WOOD	37.73	-92.13	351	x	x	x
MO	724458	NCDC	JEFFERSON CITY MEM	38.58	-92.15	167	x	x	x
MO	724459	NCDC	KAISER MEM (AWOS)	38.10	-92.55	265	x	x	x
MO	724464	NCDC	CHILLICOTHE	39.81	-93.58	234	x	x	x
MO	724467	NCDC	WHITEMAN AFB	38.71	-93.55	255	x	x	x
NC	723150	NCDC	ASHEVILLE REGIONAL	35.43	-82.53	652	x	x	x
OH	724276	NCDC	DAYTON GENERL ARPT	39.60	-84.23	293	x	x	x
OH	724280	NCDC	COLUMBUS PORT COLUM	39.98	-82.88	246	x	x	x
OH	724284	NCDC	COLUMBUS/BOLTON FLD	39.90	-83.13	280	x	x	x
OH	724285	NCDC	COLUMBUS RICKENBACK	39.81	-82.93	230	x	x	x
OH	724286	NCDC	ZANESVILLE MUNICIPA	39.95	-81.90	268	x	x	x
OH	724287	NCDC	METCALF FIELD	41.55	-83.46	189	x	x	x
OH	724288	NCDC	OHIO ST U/COLUMBUS	40.08	-83.06	276	x	x	x
OH	724290	NCDC	DAYTON INTERNATIONA	39.90	-84.21	304	x	x	x
OH	724294	NCDC	LANCASTER\FAIRFIEL	39.75	-82.65	264	x	x	x
OH	724296	NCDC	WILMINGTON AIRBORNE	39.41	-83.81	328	x	x	x
OH	724297	NCDC	CINCINNATI MUNICIPA	39.10	-84.41	149	x	x	x
OH	724298	NCDC	LIMA ALLEN CO ARPT	40.40	-84.01	296	x	x	x
OH	724303	NCDC	AKRON FULTON ASOS	41.03	-81.46	326	x	x	x
OH	725208	NCDC	MARION MUNI ARPT	40.61	-83.06	303	x	x	x
OH	725210	NCDC	AKRON AKRON-CANTON	40.91	-81.43	368	x	x	x
OH	725214	NCDC	ELYRIA/LORAIN CO.	41.35	-82.18	242	x	x	x
OH	725216	NCDC	WOOSTER	40.86	-81.88	346	x	x	x
OH	725217	NCDC	HAMILTON	39.36	-84.51	193	x	x	x
OH	725224	NCDC	NEW PHILADELPHIA	40.46	-81.41	272	x	x	x
OH	725229	NCDC	NEWARK/HEATH AIRPRT	40.01	-82.45	269	x	x	x
OH	725240	NCDC	CLEVELAND HOPKINS I	41.40	-81.85	234	x	x	x
OH	725245	NCDC	CLEVELAND/BURKELAKE	41.51	-81.68	178	x	x	x
OH	725246	NCDC	MANSFIELD LAHM MUNI	40.81	-82.51	394	x	x	x
OH	725247	NCDC	CLEVELAND/CUYAHOGA	41.56	-81.48	268	x	x	x
OH	725254	NCDC	DEFIANCE MEMORIAL	41.33	-84.41	219	x	x	x
OH	725360	NCDC	TOLEDO EXPRESS AIRP	41.58	-83.80	203	x	x	x
OH	725366	NCDC	FINDLAY AIRPORT	41.01	-83.66	243	x	x	x
OH	745700	NCDC	DAYTON WRIGHT PATTE	39.83	-84.05	249	x	x	x
OH	DCP114	CASTNET	Deer Creek	39.64	-83.26	267	x	x	x
OH	LYK123	CASTNET	Lykens	40.92	-83.00	303	x	x	x
OH	OXF122	CASTNET	Oxford	39.53	-84.73	284	x	x	x
SD	726626	NCDC	ANTIGO\LANG(AWOS)	45.15	-87.15	464	x	x	x

Table A-1 Surface Stations used in CALMET Processing

Country/State	WBAN ID	Source (1)	Name	Latitude	Longitude	Elevation (m)	2002	2003	2004
TN	723183	NCDC	BRISTOL TRI CITY AI	36.46	-82.40	457	x	x	x
TN	723246	NCDC	OAK RIDGE	36.01	-84.23	277	x	x	x
TN	723260	NCDC	KNOXVILLE MCGHEE TY	35.81	-83.98	293	x	x	x
TN	723265	NCDC	CROSSVILLE MEMORIAL	35.95	-85.08	569	x	x	x
TN	723270	NCDC	NASHVILLE INTERNATI	36.11	-86.68	176	x	x	x
TN	723347	NCDC	DYERSBURG MUNICIPAL	36.01	-89.40	102	x	x	x
TN	SPD111	CASTNET	Speedwell	36.47	-83.83	361	x	x	x
VA	724058	NCDC	ABINGTON	36.68	-82.03	631	x	x	x
VA	724117	NCDC	WISE/LONESOME PINE	36.98	-82.53	817	x	x	x
WI	726400	NCDC	MILWAUKEE MITCHELL	42.95	-87.90	204	x	x	x
WI	726404	NCDC	MINOCQUA/WOODRUFF	45.93	-89.73	496	x	x	x
WI	726405	NCDC	MILWAUKEE TIMMERMAN	43.11	-88.05	224	x	x	x
WI	726409	NCDC	WAUKESHA	43.03	-88.23	284	x	x	x
WI	726410	NCDC	MADISON DANE CO REG	43.13	-89.35	261	x	x	x
WI	726413	NCDC	WEST BEND MUNI	43.41	-88.11	270	x	x	x
WI	726414	NCDC	MONROE MUNICIPAL AI	42.60	-89.58	331	x	x	x
WI	726415	NCDC	JANESVILLE/ROCK CO.	42.61	-89.03	246	x	x	x
WI	726416	NCDC	LONE ROCK FAA AP	43.20	-90.18	219	x	x	x
WI	726417	NCDC	MEDFORD	45.10	-90.30	448	x	x	x
WI	726418	NCDC	OSCEOLA	45.31	-92.68	275	x	x	x
WI	726419	NCDC	ASHLAND KENNEDY ME	46.55	-90.91	251	x	x	x
WI	726424	NCDC	RACINE	42.76	-87.81	205	x	x	x
WI	726425	NCDC	SHEBOYGAN	43.78	-87.85	228	x	x	x
WI	726426	NCDC	STEVENS POINT	44.55	-89.53	338	x	x	x
WI	726427	NCDC	SUPERIOR	46.68	-92.10	206	x	x	x
WI	726430	NCDC	LA CROSSE MUNICIPAL	43.86	-91.25	198	x	x	x
WI	726435	NCDC	EAU CLAIRE COUNTY A	44.86	-91.48	271	x	x	x
WI	726436	NCDC	VOLK FIELD ANG	43.93	-90.26	280	x	x	x
WI	726437	NCDC	MCCOY (USA-AF)	43.96	-90.73	256	x	x	x
WI	726438	NCDC	BOSCOBEL AIRPORT	43.15	-90.42	205	x	x	x
WI	726444	NCDC	PRAIRIE DU CHIEN	43.01	-91.11	201	x	x	x
WI	726449	NCDC	MERRILL MUNI ARPT	45.18	-89.70	401	x	x	x
WI	726450	NCDC	GREEN BAY AUSTIN ST	44.48	-88.13	209	x	x	x
WI	726452	NCDC	WISCONSIN RAPIDS	44.35	-89.83	308	x	x	x
WI	726455	NCDC	MANITOWAC MUNI AWOS	44.13	-87.68	198	x	x	x
WI	726456	NCDC	OSHKOSH/WITTMAN FLD	43.96	-88.55	246	x	x	x
WI	726457	NCDC	APPLETON/OUTAGAMIE	44.25	-88.51	280	x	x	x
WI	726458	NCDC	STURGEON BAY	44.85	-87.41	221	x	x	x
WI	726463	NCDC	WAUSAU MUNICIPAL AR	44.91	-89.63	365	x	x	x
WI	726464	NCDC	WATERTOWN	43.16	-88.71	254	x	x	x
WI	726465	NCDC	MOSINEE/CENTRAL WI	44.78	-89.66	389	x	x	x
WI	726466	NCDC	APPLETON MUNI ARPT	44.55	-89.53	338	x	x	x
WI	726467	NCDC	RICE LAKE MUNICIPAL	45.48	-91.71	347	x	x	x
WI	726468	NCDC	PHILLIPS/PRICE CO.	45.70	-90.40	449	x	x	x
WI	726502	NCDC	CLINTONVILLE MUNI	44.61	-88.73	0	x	x	x
WI	726503	NCDC	WISCONSIN DELLS	43.51	-89.76	0	x	x	x
WI	726504	NCDC	EAGLE RIVER UNION	45.93	-89.26	500	x	x	x
WI	726505	NCDC	KENOSHA REGIONAL	42.60	-87.93	226	x	x	x
WI	726506	NCDC	FOND DU LAC CO.	43.76	-88.48	246		x	x
WI	726507	NCDC	MINERAL POINT	42.88	-90.23	0	x	x	x
WI	726508	NCDC	HAYWARD MUNI ARPT	46.03	-91.45	370	x	x	x
WI	726509	NCDC	JUNEAU\DODGE CO	43.43	-88.70	285	x	x	x
WI	726574	NCDC	MARSHFIELD MUNI	44.63	-90.18	389	x	x	x
WI	727415	NCDC	RHINELANDER/ONEIDA	45.63	-89.46	495	x	x	x
WI	PRK134	CASTNET	Perkinstown	45.21	-90.60	472	x	x	x
WV	724140	NCDC	CHARLESTON YEAGER A	38.38	-81.58	309	x	x	x
WV	724250	NCDC	HUNTINGTON TRI-STAT	38.38	-82.55	253	x	x	x
WV	724273	NCDC	PARKERSBURG WOOD CO	39.35	-81.43	253	x	x	x

x - Data is used in CALMET

(1) The Clean Air Status and Trends Network (CASTNET): http://www.epa.gov/castnet/site.html

National Climatic Data Center (NCDC): http://www.ncdc.noaa.gov/oa/ncdc.html

NOAA National Data Centers (NNDC): http://ols.nndc.noaa.gov/plolstore/plsql/olstore.main?look=1

Table A-2 Upper Air Stations used in CALMET Processing

State	Station Name	Station ID	Latitude	Longitude	Base Elevation (m)	2002	2003	2004
IA	DAVENPORT MUNICIPAL AP	94982	41.60	-90.57	229	x	x	x
IL	LINCOLN-LOGAN COUNTY AP	04833	40.15	-89.33	178	x	x	x
MI	GAYLORD / ALPENA	04837	44.55	-84.43	448	x	x	x
MI	DETROIT/PONTIAC	04830	42.70	-83.47	329	x	x	x
MN	INTERNATIONAL FALLS	14918	48.57	-93.38	359	x	x	x
MN	MINNEAPOLIS	94983	44.83	-93.55	287	x	x	x
MO	SPRINGFIELD REGIONAL AP	13995	37.23	-93.40	394	x	x	x
OH	WILMINGTON	13841	39.42	-83.82	317	x	x	x
PA	PITTSBURGH/MOON TOWNSHIP	94823	40.53	-80.23	360	x	x	x
TN	NASHVILLE	13897	36.25	-86.57	180	x	x	x
WI	GREEN BAY	14898	44.48	-88.13	210	x	x	x
x - Data is used in CALMET								

Table A-3 Buoy Stations used in CALMET Processing

Buoy Name	Station ID	Latitude	Longitude	Anemometer Height (m)	2002	2003	2004
N Michigan	45002	45.33	-86.42	5	x	x	x
N Huron	45003	45.35	-82.84	5	x	x	x
E Superior	45004	47.57	-86.55	5	x	x	x
S Huron	45008	44.29	-82.42	5	x	x	x
x - Data is used in CALMET							

Table A-4 Precipitation Stations used in CALMET Processing

State	ID	Station Name	Latitude	Longitude	Elevation (m)	2002	2003	2004
AR	030616	BERRYVILLE 5 NW	36.4294	-93.6256	1180	x	x	x
AR	031020	BULL SHOALS DAM	36.3647	-92.5781	480	x	x	x
AR	031632	CORNING	36.4197	-90.5858	300	x	x	x
AR	032356	EUREKA SPRINGS 3 WNW	36.4164	-93.7917	1420	x	x	x
AR	033132	HARDY	36.2747	-91.5056	400	x	x	x
AR	033165	HARRISON BOONE CNTY AP	36.2667	-93.1567	1374	x	x	x
IL	110082	ALEXIS 1 SW	41.0639	-90.5639	680	x	x	x
IL	110281	ASHLEY	38.3306	-89.1814	555	x	x	x
IL	110330	AUGUSTA	40.2378	-90.9456	680	x	x	x
IL	110510	BELLEVILLE SIU RESEARCH	38.5200	-89.8467	450	x	x	x
IL	110583	BELVIDERE	42.2550	-88.8644	738	x	x	x
IL	111166	CAIRO 3 N	37.0425	-89.1856	310	x	x	x
IL	111284	CARLINVILLE 2	39.2881	-89.8700	621	x	x	x
IL	111290	CARLYLE RESERVOIR	38.6308	-89.3658	501	x	x	x
IL	111302	CARMI 3	38.0781	-88.1831	335	x	x	x
IL	111549	CHICAGO OHARE AP	41.9950	-87.9336	658	x	x	x
IL	111577	CHICAGO MIDWAY AP 3SW	41.7372	-87.7775	620	x	x	x
IL	111664	CISNE 2 S	38.5047	-88.4094	454	x	x	x
IL	112011	CRETE	41.4492	-87.6222	664	x	x	x
IL	112140	DANVILLE	40.1389	-87.6483	558	x	x	x
IL	112193	DECATUR	39.8275	-88.9525	620	x	x	x
IL	112353	DIXON SPRINGS AGRIC CNT	37.4367	-88.6672	540	x	x	x
IL	112687	EFFINGHAM	39.1189	-88.6242	625	x	x	x
IL	112923	FAIRBURY WWTP	40.7511	-88.4983	690	x	x	x
IL	113262	FREEPORT WASTE WTR PL	42.2972	-89.6039	750	x	x	x
IL	113666	GREENFIELD	39.3425	-90.2058	548	x	x	x
IL	113683	GREENUP 3SE	39.2283	-88.1261	545	x	x	x
IL	113879	HARRISBURG	37.7408	-88.5244	365	x	x	x
IL	114198	HOOPESTON 1 NE	40.4744	-87.6558	710	x	x	x
IL	114317	HUTSONVILLE POWER PLANT	39.1333	-87.6578	455	x	x	x
IL	114355	ILLINOIS CITY DAM 16	41.4253	-91.0094	550	x	x	x
IL	114442	JACKSONVILLE 2E	39.7353	-90.2153	610	x	x	x
IL	114603	KANKAKEE METRO WASTWTR	41.1381	-87.8856	640	x	x	x
IL	114629	KASKASKIA RIV NAV LOCK	37.9842	-89.9492	380	x	x	x
IL	114710	KEWANEE 1 E	41.2483	-89.8992	780	x	x	x
IL	114805	LACON 1 N	41.0414	-89.4061	460	x	x	x
IL	114879	LANARK	42.0925	-89.8422	830	x	x	x
IL	114957	LAWRENCEVILLE	38.7267	-87.6903	442	x	x	x
IL	115272	MACKINAW 1N	40.5525	-89.3336	710	x	x	x
IL	115334	MARIETTA	40.5019	-90.3892	640	x	x	x
IL	115413	MASON CITY 1 E	40.2003	-89.6775	575	x	x	x
IL	115493	MCHENRY WG STRATTON L&D	42.3103	-88.2525	742	x	x	x
IL	115751	MOLINE WSO AP	41.4653	-90.5233	592	x	x	x
IL	115768	MONMOUTH	40.9247	-90.6392	745	x	x	x
IL	115825	MORRIS 1 NW	41.3708	-88.4336	524	x	x	x
IL	115841	MORRISONVILLE	39.4158	-89.4614	630	x	x	x
IL	115888	MT CARMEL	38.4106	-87.7578	430	x	x	x
IL	115983	MURPHYSBORO 2 SW	37.7608	-89.3656	550	x	x	x
IL	116185	NOKOMIS	39.3053	-89.2828	680	x	x	x
IL	116610	PARIS WATERWORKS	39.6356	-87.6933	680	x	x	x
IL	116711	PEORIA GTR PEORIA RGNL	40.6675	-89.6839	650	x	x	x
IL	116819	PIPER CITY	40.7569	-88.1828	670	x	x	x
IL	116837	PITTSFIELD NO 2	39.6222	-90.8058	670	x	x	x
IL	117014	PROPHETSTOWN	41.6808	-89.9403	605	x	x	x
IL	117072	QUINCY REGIONAL AP	39.9369	-91.1919	769	x	x	x
IL	117077	QUINCY DAM 21	39.9058	-91.4281	483	x	x	x
IL	117150	RANTOUL	40.3131	-88.1594	740	x	x	x
IL	117187	REND LAKE DAM	38.0406	-88.9883	455	x	x	x
IL	117382	ROCKFORD AIRPORT	42.1928	-89.0931	730	x	x	x
IL	117391	ROCK ISLAND L&D 15	41.5194	-90.5644	568	x	x	x
IL	117833	SHABBONA 3S	41.7322	-88.8653	850	x	x	x
IL	117876	SHELBYVILLE DAM	39.4106	-88.7800	655	x	x	x
IL	118020	SMITHLAND LOCK & DAM	37.1644	-88.4311	357	x	x	x
IL	118147	SPARTA 1 W	38.1167	-89.7167	535	x	x	x
IL	118179	SPRINGFIELD CAPITAL AP	39.8447	-89.6839	594	x	x	x
IL	118389	SULLIVAN 3 S	39.5608	-88.6067	659	x	x	x
IL	118740	URBANA	40.0842	-88.2406	721	x	x	x
IL	118781	VANDALIA	38.9703	-89.0922	540	x	x	x
IL	119193	WEST SALEM	38.5306	-88.0219	445	x	x	x
IL	119816	YATES CITY	40.7764	-90.0203	675	x	x	x

Table A-4 Precipitation Stations used in CALMET Processing

State	ID	Station Name	Latitude	Longitude	Elevation (m)	2002	2003	2004
IN	120132	ALPINE 2 NE	39.5736	-85.1583	850	x	x	x
IN	120177	ANDERSON SEWAGE PLANT	40.1122	-85.7175	845	x	x	x
IN	120200	ANGOLA	41.6397	-84.9900	1010	x	x	x
IN	120331	ATTICA 2E	40.2839	-87.1964	727	x	x	x
IN	120482	BATESVILLE WATERWORKS	39.2969	-85.2186	970	x	x	x
IN	120830	BLUFFTON 1 N	40.7478	-85.1733	825	x	x	x
IN	120922	BRAZIL	39.5108	-87.1242	680	x	x	x
IN	121147	BURLINGTON 1 NW	40.4875	-86.4089	724	x	x	x
IN	121256	CANNELTON	37.8994	-86.7072	402	x	x	x
IN	121415	CHALMERS	40.6628	-86.8814	700	x	x	x
IN	121628	CLINTON 2 W	39.6592	-87.4392	605	x	x	x
IN	121739	COLUMBIA CITY	41.1450	-85.4897	850	x	x	x
IN	121752	COLUMBUS UTILITIES	39.2106	-85.8883	632	x	x	x
IN	121814	CORYDON	38.2181	-86.1178	590	x	x	x
IN	121873	CRAWFORDSVILLE 6 SE	39.9664	-86.9289	840	x	x	x
IN	121929	CROTHERSVILLE	38.7908	-85.8483	560	x	x	x
IN	122309	DUBOIS SRN IN FORAGE FA	38.4558	-86.7000	690	x	x	x
IN	122738	EVANSVILLE REGIONAL AP	38.0431	-87.5203	400	x	x	x
IN	122825	FARMLAND 5 NNW	40.2539	-85.1483	965	x	x	x
IN	123037	FORT WAYNE WSO AP	41.0061	-85.2056	791	x	x	x
IN	123082	FRANKFORT DISPOSAL PLT	40.2986	-86.5067	824	x	x	x
IN	123091	FRANKLIN WWTP	39.4689	-86.0408	719	x	x	x
IN	123104	FREELANDVILLE	38.8672	-87.3083	550	x	x	x
IN	123206	GARRETT	41.3411	-85.1292	880	x	x	x
IN	123418	GOSHEN 3W	41.5575	-85.8825	875	x	x	x
IN	123714	HARRISON CRAWFORD S F	38.1975	-86.2686	850	x	x	x
IN	123777	HARTFORD CITY 4 ESE	40.4356	-85.2892	942	x	x	x
IN	124181	HUNTINGTON	40.8556	-85.4981	725	x	x	x
IN	124259	INDIANAPOLIS INTL AP	39.7317	-86.2789	790	x	x	x
IN	124286	INDIANAPOLIS ZOO	39.7681	-86.1806	710	x	x	x
IN	124372	JASPER	38.3861	-86.9408	460	x	x	x
IN	124527	KENTLAND	40.7592	-87.4353	695	x	x	x
IN	124730	LAGRANGE 1 N	41.6739	-85.4250	915	x	x	x
IN	124782	LAKEVILLE	41.5269	-86.2692	841	x	x	x
IN	124837	LA PORTE	41.6117	-86.7297	845	x	x	x
IN	124908	LEBANON WATER WORKS	40.0517	-86.4750	950	x	x	x
IN	124973	LEWISVILLE	39.8061	-85.3483	1065	x	x	x
IN	125337	MARION 2 N	40.5800	-85.6586	790	x	x	x
IN	125407	MARTINSVILLE 2 SW	39.4042	-86.4517	610	x	x	x
IN	125535	MEDARYVILLE 5 N	41.1589	-86.9014	695	x	x	x
IN	126151	NEWBURGH LOCK & DAM	37.9325	-87.3744	380	x	x	x
IN	126580	OOLITIC PURDUE EXP FRM	38.8894	-86.5519	650	x	x	x
IN	126697	PALMYRA	38.4075	-86.1106	770	x	x	x
IN	126864	PERU WASTE WATER PLANT	40.7453	-86.0717	645	x	x	x
IN	127069	PORTLAND 1 SW	40.4356	-85.2889	910	x	x	x
IN	127125	PRINCETON 1 W	38.3567	-87.5906	480	x	x	x
IN	127298	RENSSELAER	40.9356	-87.1564	650	x	x	x
IN	127370	RICHMOND WTR WKS	39.8833	-84.8833	1015	x	x	x
IN	127482	ROCHESTER	41.0658	-86.2094	770	x	x	x
IN	127930	SEYMOUR HIGHWAY GARAGE	38.9617	-85.8608	595	x	x	x
IN	127959	SHAKAMAK STATE PARK	39.1614	-87.2436	530	x	x	x
IN	127999	SHELBYVILLE SEWAGE PL	39.5283	-85.7917	750	x	x	x
IN	128036	SHOALS 8 S	38.5897	-86.7989	506	x	x	x
IN	128187	SOUTH BEND WSO AP	41.7072	-86.3331	773	x	x	x
IN	128442	STENDAL	38.2692	-87.1631	635	x	x	x
IN	128784	TIPTON 5 SW	40.2233	-86.1086	895	x	x	x
IN	128967	J T MYERS LOCKS & DAM	37.7953	-87.9931	340	x	x	x
IN	128999	VALPARAISO WATERWORKS	41.5114	-87.0378	800	x	x	x
IN	129069	VERSAILLES WATERWORKS	39.0717	-85.2453	939	x	x	x
IN	129174	WALDRON 2 W	39.4539	-85.6964	825	x	x	x
IN	129430	WEST LAFAYETTE 6 NW	40.4750	-86.9919	715	x	x	x
IA	130149	ALLERTON	40.7039	-93.3639	1090	x	x	x
IA	130608	BELLEVUE L AND D 12	42.2614	-90.4233	603	x	x	x
IA	131060	BURLINGTON RADIO KBUR	40.8167	-91.1667	703	x	x	x
IA	131257	CASCADE	42.2975	-91.0133	850	x	x	x
IA	131354	CENTERVILLE	40.7364	-92.8692	980	x	x	x
IA	131363	CENTRAL CITY	42.2011	-91.5286	870	x	x	x
IA	131724	COLUMBIA	41.1756	-93.1522	950	x	x	x
IA	132195	DERBY	40.9308	-93.4581	1190	x	x	x
IA	132203	DES MOINES AP	41.5339	-93.6531	957	x	x	x

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Table A-4 Precipitation Stations used in CALMET Processing

State	ID	Station Name	Latitude	Longitude	Elevation (m)	2002	2003	2004
IA	132367	DUBUQUE WSO AP	42.3978	-90.7036	1056	x	x	x
IA	132977	FOREST CITY 2 NNE	43.2844	-93.6306	1300	x	x	x
IA	133473	GRINNELL 3 SW	41.7203	-92.7489	905	x	x	x
IA	134101	IOWA CITY	41.6092	-91.5050	640	x	x	x
IA	134142	IOWA FALLS	42.5189	-93.2536	1130	x	x	x
IA	134381	KEOKUK LOCK DAM 19	40.3969	-91.3767	527	x	x	x
IA	134502	KNOXVILLE	41.3336	-93.1117	920	x	x	x
IA	134963	LOWDEN	41.8564	-90.9300	715	x	x	x
IA	135198	MARSHALLTOWN	42.0647	-92.9244	870	x	x	x
IA	135235	MASON CITY MUNI AP	43.1544	-93.3269	1225	x	x	x
IA	135295	MAXWELL	41.8875	-93.3919	875	x	x	x
IA	135315	MCGREGOR	43.0239	-91.1747	627	x	x	x
IA	135796	MOUNT PLEASANT 1 SSW	40.9486	-91.5647	730	x	x	x
IA	136076	NORTH ENGLISH	41.5119	-92.0725	797	x	x	x
IA	136389	OTTUMWA INDUSTRIAL AP	41.1078	-92.4467	842	x	x	x
IA	137326	ST ANSGAR	43.3817	-92.9156	1170	x	x	x
IA	137572	SHEFFIELD 3 NW	42.9217	-93.2828	1045	x	x	x
IA	137602	SHELL ROCK 2W	42.7081	-92.6153	912	x	x	x
IA	137855	SPILLVILLE	43.2053	-91.9536	1080	x	x	x
IA	137985	STORY CITY	42.1792	-93.5817	975	x	x	x
IA	138009	STRAWBERRY POINT	42.6842	-91.5353	1200	x	x	x
IA	138315	TRAER	42.1869	-92.4728	950	x	x	x
IA	138688	WASHINGTON	41.2828	-91.7069	690	x	x	x
IA	138706	WATERLOO MUNICIPAL AP	42.5544	-92.4011	868	x	x	x
KY	150381	BARBOURVILLE	36.8825	-83.8819	990	x	x	x
KY	150450	BAXTER	36.8583	-83.3303	1164	x	x	x
KY	150611	BENTON	36.8581	-88.3364	365	x	x	x
KY	150619	BEREA COLLEGE	37.5733	-84.2908	1070	x	x	x
KY	151080	BUCKHORN LAKE	37.3500	-83.3833	936	x	x	x
KY	151227	CALHOUN LOCK 2	37.5317	-87.2667	402	x	x	x
KY	151631	CLINTON 4 S	36.6267	-88.9608	350	x	x	x
KY	151855	COVINGTON WSO	39.0431	-84.6717	869	x	x	x
KY	152358	DUNDEE 2NE	37.5806	-86.7769	450	x	x	x
KY	152979	FORDSVILLE	37.6372	-86.7206	480	x	x	x
KY	153741	HEIDELBERG	37.5500	-83.7667	665	x	x	x
KY	153798	HERNDON 5 S	36.6703	-87.5589	560	x	x	x
KY	153929	HODGENVILLE-LINCOLN NP	37.5317	-85.7350	788	x	x	x
KY	154202	JACKSON WSO	37.5914	-83.3144	1365	x	x	x
KY	154650	LEBANON 5 S	37.5050	-85.3086	660	x	x	x
KY	154746	LEXINGTON BLUEGRASS AP	38.0408	-84.6058	980	x	x	x
KY	154948	LOUISA 5 W	38.1250	-82.6947	753	x	x	x
KY	154954	LOUISVILLE INTL AP	38.1811	-85.7392	488	x	x	x
KY	154955	LOUISVILLE UPPER GAGE	38.2833	-85.8000	440	x	x	x
KY	155067	MADISONVILLE	37.3467	-87.5244	440	x	x	x
KY	155243	MAYSVILLE SEWAGE PLANT	38.6869	-83.7872	515	x	x	x
KY	155555	MOREHEAD 3 NW	38.2167	-83.4833	830	x	x	x
KY	155684	MUNFORDVILLE 5 NW	37.3347	-85.9503	680	x	x	x
KY	156012	OLIVE HILL 5 NE	38.3422	-83.1036	891	x	x	x
KY	156110	PADUCAH BARKLEY AP	37.0564	-88.7742	413	x	x	x
KY	156170	PARIS	38.2047	-84.2392	810	x	x	x
KY	156580	PRINCETON 1 SE	37.1244	-87.8672	497	x	x	x
KY	157074	SADIEVILLE	38.4078	-84.6836	945	x	x	x
KY	157473	SMITHFIELD 4 S	38.3333	-85.2861	850	x	x	x
KY	157508	SOMERSET 2 NE	37.1167	-84.6000	955	x	x	x
KY	157622	STAFFORDSVILLE 2 NW	37.8500	-82.8667	760	x	x	x
KY	157677	STEARNS 2 S	36.6667	-84.4833	1220	x	x	x
KY	158070	TOMPKINSVILLE 9 NW	36.8136	-85.7081	1060	x	x	x
KY	158719	WILLISBURG	37.8014	-85.1131	870	x	x	x
KY	158824	WOODBURY	37.1842	-86.6353	465	x	x	x
MI	200128	ALLEGAN 5 NE	42.5797	-85.7894	750	x	x	x
MI	200164	ALPENA COUNTY RGNL AP	45.0717	-83.5644	684	x	x	x
MI	200230	ANN ARBOR U OF MICH	42.2947	-83.7108	900	x	x	x
MI	200373	AVOCA 4 N	43.1256	-82.6886	770	x	x	x
MI	200662	BELLAIRE	44.9758	-85.1978	625	x	x	x
MI	200766	BIG BAY 8 NW	46.8867	-87.8642	612	x	x	x
MI	201088	BRUCE CROSSING	46.5333	-89.1833	1135	x	x	x
MI	201361	CASS CITY 1 SSW	43.5861	-83.1806	698	x	x	x
MI	201486	CHATHAM EXP FARM 2	46.3467	-86.9289	870	x	x	x
MI	201680	COLDWTR WASTEWTR PLT	41.9397	-85.0183	950	x	x	x
MI	201780	COPPER HARBOR FT WILKIN	47.4675	-87.8669	625	x	x	x

Table A-4 Precipitation Stations used in CALMET Processing

State	ID	Station Name	Latitude	Longitude	Elevation (m)	2002	2003	2004
MI	202094	DETOUR VILLAGE	45.9983	-83.9014	595	x	x	x
MI	202103	DETROIT METRO AP	42.2314	-83.3308	631	x	x	x
MI	202395	EAST LANSING 4 S	42.6742	-84.4850	880	x	x	x
MI	202626	ESCANABA	45.7500	-87.0333	591	x	x	x
MI	202788	FIFE LAKE 3WSW	44.5650	-85.4133	1112	x	x	x
MI	202846	FLINT BISHOP INTL AP	42.9667	-83.7494	770	x	x	x
MI	203170	GLADWIN	43.9758	-84.4908	775	x	x	x
MI	203199	GLENNIE ALCONA DAM	44.5617	-83.8031	805	x	x	x
MI	203295	GRAND HAVEN WASTEWTR PL	43.0608	-86.2047	605	x	x	x
MI	203333	GRAND RAPIDS INTL AP	42.8825	-85.5239	803	x	x	x
MI	203391	GRAYLING	44.6542	-84.6994	1136	x	x	x
MI	203516	GWINN 1 W	46.2864	-87.4511	1162	x	x	x
MI	203585	HARBOR BEACH 1 SSE	43.8322	-82.6428	595	x	x	x
MI	203936	HOUGHTON LAKE ROSCOMMON	44.3592	-84.6739	1151	x	x	x
MI	203947	HOWELL WWTP	42.5936	-83.9322	917	x	x	x
MI	204090	IRON MTN-KINGSFORD WWTP	45.7858	-88.0842	1071	x	x	x
MI	204155	JACKSON 3 N	42.2833	-84.4167	950	x	x	x
MI	204320	KENT CITY 2 SW	43.1994	-85.7717	840	x	x	x
MI	204641	LANSING CAPITAL CITY A	42.7803	-84.5789	841	x	x	x
MI	205073	MANISTIQUE WWTP	45.9511	-86.2511	620	x	x	x
MI	205567	MONTAGUE 4 NW	43.4614	-86.4175	650	x	x	x
MI	205712	MUSKEGON COUNTY AP	43.1711	-86.2367	625	x	x	x
MI	205816	NEWBERRY 3 S	46.3133	-85.5106	850	x	x	x
MI	206215	ONTONAGON	46.8561	-89.3119	673	x	x	x
MI	206300	OWOSSO WWTP	43.0161	-84.1800	730	x	x	x
MI	206438	PELLSTON REGIONAL AP	45.5644	-84.7928	705	x	x	x
MI	207366	SAULT STE MARIE SNDRSN	46.4794	-84.3572	722	x	x	x
MI	207812	STAMBAUGH 2 SSE	46.0556	-88.6278	1450	x	x	x
MI	207828	STANTON	43.2908	-85.0922	930	x	x	x
MI	208246	TRAVERSE CITY	44.7683	-85.5761	604	x	x	x
MI	208293	TROUT LAKE 2WNW	46.1989	-85.0728	871	x	x	x
MI	208417	VANDERBILT 11ENE	45.1703	-84.4397	905	x	x	x
MI	208443	VASSAR	43.3656	-83.5828	630	x	x	x
MI	208559	WAKEFIELD	46.4792	-89.9322	1600	x	x	x
MI	209218	YPSILANTI E MICH U	42.2475	-83.6253	780	x	x	x
MN	210075	ALBERT LEA 3 SE	43.6064	-93.3019	1230	x	x	x
MN	211227	CAMBRIDGE 5ESE	45.5506	-93.1264	960	x	x	x
MN	212166	DODGE CENTER	44.0419	-92.8814	1250	x	x	x
MN	212248	DULUTH INTL AP	46.8369	-92.1833	1433	x	x	x
MN	212543	ELY	47.9239	-91.8586	1382	x	x	x
MN	212645	EVELETH WASTE WATER PLA	47.4581	-92.5303	1445	x	x	x
MN	212842	FLOODWOOD 3 NE	46.9728	-92.8700	1260	x	x	x
MN	213202	GOLDEN VALLEY	44.9944	-93.4075	910	x	x	x
MN	213417	GUNFLINT LAKE 10 NW	48.1603	-90.8842	1455	x	x	x
MN	213793	HINCKLEY	45.9919	-92.9928	1035	x	x	x
MN	213863	HOLYOKE	46.4675	-92.3903	1034	x	x	x
MN	214418	LA CRESCENT DAM 7	43.8658	-91.3100	647	x	x	x
MN	215435	MINNEAPOLIS/ST PAUL AP	44.8831	-93.2289	872	x	x	x
MN	215987	NORTHFIELD 2 NNE	44.4761	-93.1486	890	x	x	x
MN	216213	ORR	48.0553	-92.8425	1390	x	x	x
MN	216822	RED WING DAM 3	44.6103	-92.6100	677	x	x	x
MN	217004	ROCHESTER INTERNATIONAL	43.9042	-92.4917	1304	x	x	x
MN	217184	RUSHFORD	43.8053	-91.7500	770	x	x	x
MN	217460	SANDY LAKE DAM LIBBY	46.7953	-93.3211	1234	x	x	x
MN	217941	SPRING VALLEY	43.6933	-92.3925	1280	x	x	x
MN	218280	TOFTE RANGER STATION	47.5681	-90.8500	680	x	x	x
MN	218613	WALES 2E	47.2561	-91.7017	1675	x	x	x
MO	230022	ADVANCE 1 S	37.0956	-89.9058	360	x	x	x
MO	230088	ALLEY SPRING RGR STA	37.1528	-91.4439	700	x	x	x
MO	230789	BOLIVAR 1 NE	37.6167	-93.3911	1034	x	x	x
MO	231283	CAP AU GRIS LOCK & DAM	39.0031	-90.6886	450	x	x	x
MO	231600	CLARENCE CANNON DAM	39.5253	-91.6450	702	x	x	x
MO	231640	CLARKSVILLE L&D 24	39.3731	-90.9053	460	x	x	x
MO	231674	CLEARWATER DAM	37.1319	-90.7756	660	x	x	x
MO	231711	CLINTON	38.3950	-93.7711	770	x	x	x
MO	231791	COLUMBIA REGIONAL AP	38.8169	-92.2183	893	x	x	x
MO	232302	DORA	36.7797	-92.2328	990	x	x	x
MO	232318	DOWNING	40.4822	-92.3636	870	x	x	x
MO	232809	FARMINGTON	37.7922	-90.4103	928	x	x	x
MO	233079	FULTON	38.8581	-91.9300	870	x	x	x

Table A-4 Precipitation Stations used in CALMET Processing

State	ID	Station Name	Latitude	Longitude	Elevation (m)	2002	2003	2004
MO	233601	HANNIBAL WATER WORKS	39.7233	-91.3719	712	x	x	x
MO	234271	JEFFERSON CITY WTR PL	38.5850	-92.1825	670	x	x	x
MO	234273	JEFFERSON BARRACKS	38.5039	-90.2800	490	x	x	x
MO	234544	KIRKSVILLE	40.2058	-92.5747	970	x	x	x
MO	234825	LEBANON 2W	37.6850	-92.6936	1279	x	x	x
MO	234919	LICKING 4N	37.5544	-91.8831	1180	x	x	x
MO	235050	LONG BRANCH RESERVOIR	39.7506	-92.5064	820	x	x	x
MO	235130	LURAY 2 N	40.4892	-91.8781	740	x	x	x
MO	235207	MALDEN MUNICIPAL AP	36.5994	-89.9894	290	x	x	x
MO	235298	MARSHALL	39.1342	-93.2225	790	x	x	x
MO	235307	MARSHFIELD	37.3381	-92.9097	1490	x	x	x
MO	235415	MC CREDIE EXPERIMENT ST	38.9500	-91.9000	850	x	x	x
MO	235562	MIDDLETOWN	39.1244	-91.4142	680	x	x	x
MO	235594	MILLER 1 E	37.2147	-93.8228	1296	x	x	x
MO	235671	MOBERLY	39.4194	-92.4369	860	x	x	x
MO	235834	MOUNTAIN GROVE 2 N	37.1528	-92.2636	1450	x	x	x
MO	236012	NEW FRANKLIN 1 W	39.0172	-92.7558	641	x	x	x
MO	236460	OZARK BEACH	36.6597	-93.1261	700	x	x	x
MO	236777	POMME DE TERRE DAM	37.9050	-93.3169	900	x	x	x
MO	236826	POTOSI 5 SW	37.8908	-90.8600	1030	x	x	x
MO	237263	ROLLA UNI OF MISSOURI	37.9572	-91.7758	1167	x	x	x
MO	237300	ROSEBUD	38.4506	-91.3756	960	x	x	x
MO	237452	ST LOUIS SCIENCE CENTER	38.6292	-90.2706	545	x	x	x
MO	237455	ST LOUIS LAMBERT INTL	38.7525	-90.3736	531	x	x	x
MO	237506	SALEM	37.6331	-91.5364	1200	x	x	x
MO	237976	SPRINGFIELD REG AP	37.2397	-93.3897	1259	x	x	x
MO	238043	STEELVILLE 2 N	38.0053	-91.3706	700	x	x	x
MO	238051	STEFFENVILLE	39.9714	-91.8872	690	x	x	x
MO	238082	STOCKTON DAM	37.6967	-93.7722	873	x	x	x
MO	238223	SWEET SPRINGS	38.9631	-93.4000	670	x	x	x
MO	238252	TABLE ROCK DAM	36.5972	-93.3075	820	x	x	x
MO	238466	TRUMAN DAM & RESERVOIR	38.2581	-93.3989	632	x	x	x
MO	238609	VIBURNUM	37.7119	-91.1328	1276	x	x	x
MO	238620	VIENNA 2 WNW	38.2017	-91.9811	770	x	x	x
MO	238700	WAPPAPELLO DAM	36.9231	-90.2836	410	x	x	x
MO	238712	WARRENSBURG 4 NW	38.7842	-93.8008	796	x	x	x
MO	238746	WASHINGTON	38.5425	-90.9719	490	x	x	x
MO	238827	WENTZVILLE	38.8128	-90.8561	580	x	x	x
MO	238880	WEST PLAINS	36.7425	-91.8347	1010	x	x	x
OH	330058	AKRON CANTON WSO AP	40.9167	-81.4333	1208	x	x	x
OH	330059	AKRON WPCS	41.1500	-81.5667	750	x	x	x
OH	330107	ALLIANCE 3 NNW	40.9550	-81.1169	1055	x	x	x
OH	330256	ASHLAND 2 SW	40.8333	-82.3500	1265	x	x	x
OH	330493	BEACH CITY LAKE	40.6333	-81.5667	985	x	x	x
OH	330639	BERLIN LAKE	41.0333	-81.0167	1040	x	x	x
OH	330862	BOWLING GREEN WWTP	41.3831	-83.6111	675	x	x	x
OH	331042	BRYAN 2 SE	41.4619	-84.5272	730	x	x	x
OH	331197	CAMBRIDGE	40.0167	-81.5833	800	x	x	x
OH	331404	CENTERBURG 2 SE	40.3000	-82.6500	1205	x	x	x
OH	331466	CHARLES MILL LAKE	40.7400	-82.3569	1025	x	x	x
OH	331528	CHILLICOTHE MOUND CITY	39.3744	-83.0036	650	x	x	x
OH	331536	CHILO MELDAHL L&D	38.7983	-84.1731	500	x	x	x
OH	331541	CHIPPEWA LAKE	41.0517	-81.9361	1180	x	x	x
OH	331592	CIRCLEVILLE	39.6106	-82.9547	673	x	x	x
OH	331651	CLEVELAND EASTERLY	41.5667	-81.5833	550	x	x	x
OH	331657	CLEVELAND WSFO AP	41.4050	-81.8528	770	x	x	x
OH	331786	COLUMBUS WSO AIRPORT	39.9914	-82.8808	810	x	x	x
OH	331905	COSHOCTON AGRI RS STA	40.3708	-81.7908	1140	x	x	x
OH	332075	DAYTON WSO AIRPORT	39.9061	-84.2186	1000	x	x	x
OH	332090	DEER CREEK LAKE	39.6253	-83.2128	860	x	x	x
OH	332098	DEFIANCE	41.2778	-84.3853	700	x	x	x
OH	332124	DELAWARE LAKE	40.3667	-83.0667	930	x	x	x
OH	332272	DOVER DAM	40.5667	-81.4167	930	x	x	x
OH	332485	EATON	39.7347	-84.6336	1002	x	x	x
OH	332651	FAIRFIELD	39.3500	-84.5833	575	x	x	x
OH	332791	FINDLAY WPCC	41.0461	-83.6622	768	x	x	x
OH	332956	FREDERICKTOWN 4 S	40.4167	-82.5333	1050	x	x	x
OH	332974	FREMONT	41.3333	-83.1167	600	x	x	x
OH	333021	GALION WATER WORKS	40.7167	-82.8000	1170	x	x	x

Table A-4 Precipitation Stations used in CALMET Processing

State	ID	Station Name	Latitude	Longitude	Elevation (m)	2002	2003	2004
OH	333120	GERMANTOWN DAM	39.6358	-84.4003	740	x	x	x
OH	333356	GREENFIELD 1 WNW	39.3542	-83.4056	970	x	x	x
OH	333375	GREENVILLE WATER PLANT	40.1000	-84.6500	1024	x	x	x
OH	333758	HILLSBORO	39.2000	-83.6167	1100	x	x	x
OH	334004	JACKSON 3 NW	39.0775	-82.7053	800	x	x	x
OH	334189	KENTON	40.6489	-83.6061	995	x	x	x
OH	334403	LANCASTER	39.7156	-82.6072	840	x	x	x
OH	334459	LEBANON 4 SE	39.3689	-84.2394	680	x	x	x
OH	334473	LEESVILLE LAKE	40.4667	-81.2000	980	x	x	x
OH	334551	LIMA WWTP	40.7247	-84.1294	850	x	x	x
OH	334672	LOGAN	39.5292	-82.3850	722	x	x	x
OH	334681	LONDON	39.8833	-83.4500	1020	x	x	x
OH	334865	MANSFIELD WSO AP	40.8203	-82.5178	1295	x	x	x
OH	334942	MARION 2 N	40.6167	-83.1333	965	x	x	x
OH	334979	MARYSVILLE	40.2411	-83.3669	1000	x	x	x
OH	334992	MASSILLON	40.7667	-81.5333	930	x	x	x
OH	335029	MC ARTHUR	39.2503	-82.4822	785	x	x	x
OH	335041	MC CONNELSVILLE LOCK 7	39.6539	-81.8569	760	x	x	x
OH	335297	MILLERSBURG	40.5500	-81.9167	819	x	x	x
OH	335398	MOHAWK DAM	40.3486	-82.0908	865	x	x	x
OH	335585	MOUNT VERNON	40.3833	-82.4667	980	x	x	x
OH	335747	NEWARK WATER WORKS	40.0875	-82.4131	835	x	x	x
OH	336123	NORWALK 5 SE	41.1833	-82.5667	925	x	x	x
OH	336196	OBERLIN	41.2667	-82.2167	816	x	x	x
OH	336375	OXFORD	39.5167	-84.7333	860	x	x	x
OH	336616	PIEDMONT LAKE	40.1833	-81.2167	940	x	x	x
OH	336650	PIQUA WWTP	40.1311	-84.2342	800	x	x	x
OH	336702	PLEASANT HILL LAKE	40.6167	-82.3333	1125	x	x	x
OH	336781	PORTSMOUTH SCIOTOVILLE	38.7569	-82.8872	540	x	x	x
OH	336949	RAVENNA 2 S	41.1333	-81.2833	1107	x	x	x
OH	337383	ST MARYS 3 W	40.5447	-84.4375	875	x	x	x
OH	337559	SENECAVILLE LAKE	39.9222	-81.4347	875	x	x	x
OH	337698	SIDNEY HIGHWAY DEPT	40.2983	-84.1633	1030	x	x	x
OH	337935	SPRINGFIELD NEW WTR WKS	39.9667	-83.8167	930	x	x	x
OH	338240	TAPPAN DAM	40.3561	-81.2281	950	x	x	x
OH	338313	TIFFIN	41.1167	-83.1667	740	x	x	x
OH	338357	TOLEDO EXPRESS WSO AP	41.5886	-83.8014	669	x	x	x
OH	338378	TOM JENKINS DAM-BURR OA	39.5444	-82.0589	760	x	x	x
OH	338539	UPPER SANDUSKY WATER WK	40.8167	-83.2833	820	x	x	x
OH	338552	URBANA WWTP	40.1000	-83.7833	1000	x	x	x
OH	338810	WATERLOO	38.7003	-82.4736	625	x	x	x
OH	339211	WILLS CREEK LAKE	40.1500	-81.8500	780	x	x	x
OH	339224	WILMINGTON	39.4333	-83.8500	975	x	x	x
OH	339312	WOOSTER EXP STN	40.7833	-81.9167	1020	x	x	x
OH	339357	XENIA TREATMENT PLANT	39.7167	-83.9667	820	x	x	x
OH	339422	ZANESVILLE WWTP	39.9125	-82.0042	700	x	x	x
TN	401094	BRISTOL AP	36.4731	-82.4044	1500	x	x	x
TN	401561	CELINA	36.5408	-85.4594	540	x	x	x
TN	401663	CHEATHAM LOCK & DAM	36.3244	-87.2244	392	x	x	x
TN	405332	LIVINGSTON RADIO WLIV	36.3772	-85.3394	975	x	x	x
TN	407359	PORTLAND SEWAGE PLANT	36.5875	-86.5258	794	x	x	x
TN	407884	ROGERSVILLE 1 NE	36.4161	-82.9839	1355	x	x	x
TN	408065	SAMBURG W. L. REFUGE	36.4528	-89.3028	310	x	x	x
TN	408562	SPRINGFIELD EXPERIMENT	36.4739	-86.8472	745	x	x	x
TN	409219	UNION CITY	36.3925	-89.0317	350	x	x	x
VA	444180	HURLEY 4 S	37.3653	-82.0561	1088	x	x	x
VA	449215	WISE 3E	36.9986	-82.5389	2549	x	x	x
WV	461570	CHARLESTON YEAGER AP	38.3794	-81.5914	910	x	x	x
WV	461579	CHARLESTON WSFO	38.3139	-81.7186	918	x	x	x
WV	463749	GRIFFITHSVILLE	38.2381	-81.9853	780	x	x	x
WV	464393	HUNTINGTON TRI/STATE	38.3650	-82.5550	824	x	x	x
WV	465323	LIVERPOOL	38.8956	-81.5311	665	x	x	x
WV	465353	LOGAN	37.8611	-81.9961	640	x	x	x
WV	468351	SOUTHSIDE 3 NNW	38.7506	-81.9808	576	x	x	x
WI	470045	AFTON	42.6475	-89.0644	742	x	x	x
WI	470124	ALMA DAM 4	44.3272	-91.9194	670	x	x	x

Table A-4 Precipitation Stations used in CALMET Processing

State	ID	Station Name	Latitude	Longitude	Elevation (m)	2002	2003	2004
WI	470308	ARLINGTON UNIV FARM	43.3008	-89.3269	1080	x	x	x
WI	470349	ASHLAND EXP FARM	46.5728	-90.9714	650	x	x	x
WI	470456	BABCOCK 1 WNW	44.2994	-90.1306	980	x	x	x
WI	470855	BLACK RVR FALLS SWG	44.2903	-90.8536	810	x	x	x
WI	470890	BLANCHARDVILLE	42.8169	-89.8628	830	x	x	x
WI	471416	CHARMANY FARM	43.0603	-89.4781	910	x	x	x
WI	471568	CHILTON	44.0328	-88.1469	840	x	x	x
WI	471578	CHIPPEWA FALLS	44.9278	-91.4081	850	x	x	x
WI	471667	CLINTON	42.5492	-88.8753	960	x	x	x
WI	471676	CLINTONVILLE	44.6225	-88.7483	800	x	x	x
WI	471897	CRIVITZ HIGH FALLS	45.3581	-88.1925	1050	x	x	x
WI	471913	CUBA CITY 2NW	42.6253	-90.4592	900	x	x	x
WI	472447	EAU PLEINE RESERVOIR	44.7247	-89.7567	1138	x	x	x
WI	472973	FRIENDSHIP	43.9750	-89.8308	945	x	x	x
WI	473038	GENOA DAM 8	43.5706	-91.2294	639	x	x	x
WI	473269	GREEN BAY A S INTL AP	44.4794	-88.1378	687	x	x	x
WI	473453	HARTFORD 2 W	43.3311	-88.4114	980	x	x	x
WI	473511	HAYWARD RANGER STA	46.0003	-91.5075	1200	x	x	x
WI	473636	HILES	45.6811	-88.9603	1633	x	x	x
WI	473756	HORICON	43.4406	-88.6325	880	x	x	x
WI	474370	LA CROSSE MUNICIPAL AIR	43.8789	-91.2528	652	x	x	x
WI	474396	LADYSMITH WTP	45.4431	-91.0894	1160	x	x	x
WI	474404	LA FARGE	43.5753	-90.6417	810	x	x	x
WI	474546	LANCASTER 4 WSW	42.8278	-90.7889	1040	x	x	x
WI	474894	LUCK	45.5733	-92.4850	1220	x	x	x
WI	474937	LYNXVILLE DAM 9	43.2117	-91.0986	633	x	x	x
WI	474961	MADISON DANE COUNTY AP	43.1406	-89.3453	866	x	x	x
WI	475120	MARSHFIELD EXP FARM	44.6322	-90.1314	1250	x	x	x
WI	475255	MEDFORD	45.1308	-90.3439	1470	x	x	x
WI	475335	MENOMONIE	44.8742	-91.9364	780	x	x	x
WI	475352	MERCER RANGER STN	46.1683	-90.0722	1600	x	x	x
WI	475364	MERRILL	45.1706	-89.6614	1253	x	x	x
WI	475479	MILWAUKEE MITCHELL AP	42.9550	-87.9044	670	x	x	x
WI	475524	MINONG RANGER STN	46.1006	-91.8178	1080	x	x	x
WI	475948	NEW RICHMOND	45.1167	-92.5639	1000	x	x	x
WI	476398	PARK FALLS DNR HQ	45.9336	-90.4506	1525	x	x	x
WI	476510	PESHTIGO	45.0203	-87.7342	600	x	x	x
WI	476518	PHELPS	46.0658	-89.0756	1776	x	x	x
WI	476718	PORTAGE	43.5278	-89.4342	775	x	x	x
WI	476854	PRENTICE	45.5478	-90.2883	1540	x	x	x
WI	476939	RAINBOW RSVR-LK TOMAHAW	45.8342	-89.5494	1600	x	x	x
WI	477132	RICE LAKE	45.4164	-91.7719	1103	x	x	x
WI	477140	RICE RESERVOIR TOMAHAWK	45.5406	-89.7481	1465	x	x	x
WI	478027	SPOONER EXPERMNT FARM	45.8236	-91.8761	1100	x	x	x
WI	478259	STRUM 4 S	44.4964	-91.3964	976	x	x	x
WI	478267	STURGEON BAY EXP FARM	44.8722	-87.3353	656	x	x	x
WI	478316	SULLIVAN 3SE	42.9675	-88.5497	933	x	x	x
WI	478515	TOMAH RANGER STATION	43.9908	-90.5053	960	x	x	x
WI	478589	TREMPEALEAU DAM 6	43.9994	-91.4378	660	x	x	x
WI	479176	WHITE LAKE 3 NE	45.1817	-88.7344	1285	x	x	x
WI	479218	WILLARD	44.7314	-90.7217	1490	x	x	x
WI	479304	WINTER	45.8231	-91.0139	1397	x	x	x
x - Data is used in CALMET								

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
14 October 2006

Introduction

CALPOST can be used to processes 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]

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

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

$$[large\ sulfate] = \{[total\ sulfate]/20\} \bullet [total\ sulfate]\ if\ [total\ sulfate] < 20\ \mu g^3$$

$$[large\ sulfate] = [total\ sulfate]\ if\ [total\ sulfate] \geq 20\ \mu g/m^3 \qquad \text{(Eqs. 2)}$$

$$[small\ sulfate] = [total\ sulfate] - [large\ sulfate].$$

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

The sea salt concentration is taken to be 1.8•[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;

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[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(RH) against RH, and then also lists values for the three new humidity growth functions, $f_S(RH)$, $f_L(RH)$, and $f_{SS}(RH)$. 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 NO_2 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 NO_2. 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       27.145
25.38   3.500  5.401  0.045  0.042  0.002  0.001  0.004     1
2002 172  0  1021         1479.244     23.778   D       4.923      21.650       26.573
22.74   3.500  4.475  0.404  0.038  0.001  0.001  0.004     2
2002 284  0  1045         1484.348     27.580   D       3.150      21.470       24.620
14.67   3.300  2.684  0.428  0.033  0.001  0.001  0.003     3
2002 353  0  1026         1482.762     24.457   D       2.594      21.290       23.884
12.18   3.100  2.017  0.557  0.018  0.001  0.000  0.002     4
2002 283  0  1026         1482.762     24.457   D       2.502      21.470       23.972
11.65   3.300  2.269  0.201  0.028  0.001  0.001  0.003     5
2002 195  0  1045         1484.348     27.580   D       2.011      21.830       23.841
9.21   3.700  1.963  0.031  0.015  0.001  0.000  0.001    6
2002  20  0  1117         1486.636     34.592   D       1.872      21.200       23.072
8.83   3.000  1.542  0.320  0.009  0.000  0.000  0.001    7
2002 173  0  1128         1479.259     35.042   D       1.649      21.650       23.299
7.62   3.500  1.625  0.012  0.010  0.000  0.000  0.001    8
2002 234  0  1021         1479.244     23.778   D       1.524      22.190       23.714
6.87   4.100  1.482  0.029  0.011  0.000  0.000  0.001    9
2002 298  0  1021         1479.244     23.778   D       1.459      21.470       22.929
6.80   3.300  1.284  0.160  0.014  0.001  0.000  0.001   10
2002 299  0  1021         1479.244     23.778   D       1.436      21.470       22.906
6.69   3.300  1.281  0.140  0.013  0.000  0.000  0.001   11
2002 275  0  1026         1482.762     24.457   D       1.270      21.470       22.740
5.92   3.300  1.202  0.058  0.009  0.000  0.000  0.001   12
2002 263  0  1045         1484.348     27.580   D       1.237      22.100       23.337
5.60   4.000  1.223  0.008  0.005  0.000  0.000  0.001   13
2002 252  0  1026         1482.762     24.457   D       1.189      22.100       23.289
5.38   4.000  1.166  0.013  0.009  0.000  0.000  0.001   14
2002 285  0  1021         1479.244     23.778   D       0.992      21.470       22.462
4.62   3.300  0.813  0.179  0.001  0.000  0.000  0.000   15
2002 161  0  1026         1482.762     24.457   D       0.873      21.650       22.523
4.03   3.500  0.842  0.020  0.009  0.000  0.000  0.001   16
2002 150  0  1026         1482.762     24.457   D       0.857      21.380       22.237
4.01   3.200  0.822  0.026  0.007  0.000  0.000  0.001   17
2002 340  0  1140         1481.017     37.258   D       0.817      21.290       22.107
3.84   3.100  0.663  0.153  0.001  0.000  0.000  0.000   18
2002 151  0  1117         1486.636     34.592   D       0.745      21.380       22.125
3.49   3.200  0.704  0.033  0.007  0.000  0.000  0.001   19
2002 160  0  1021         1479.244     23.778   D       0.735      21.650       22.385
3.40   3.500  0.710  0.014  0.010  0.000  0.000  0.001   20
2002 346  0  1021         1479.244     23.778   D       0.703      21.290       21.993
3.30   3.100  0.620  0.080  0.002  0.000  0.000  0.000   21
2002 247  0  1021         1479.244     23.778   D       0.661      22.100       22.761
2.99   4.000  0.654  0.004  0.002  0.000  0.000  0.000   22
```

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.

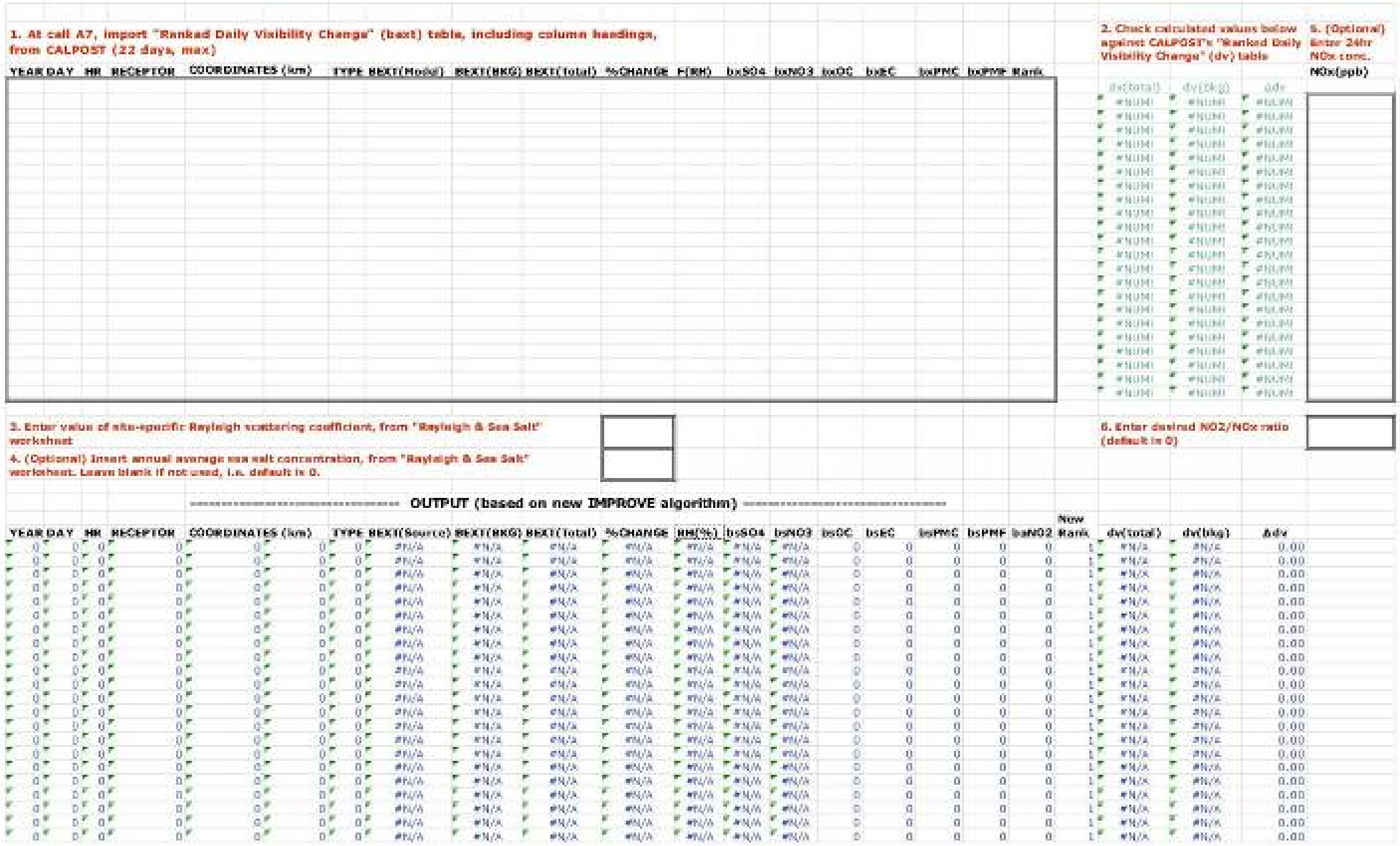

Figure 2. Example of Appearance of Input & Output Worksheet before Data Entry.

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 NO_2 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 NO_2. 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(RH) column in the top table is replaced by just the RH in the lower table (since the new procedure has three different f(RH) functions) and a new $baNO_2$ column has been added to the bottom table to show the light absorption due to NO_2 (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 NO_2 is not of interest, just leave the entry fields mentioned in these steps blank.

[10] An easy way to see the effect of the NO_2 on the source's impact in the output table in the lower half of the page is to toggle this NO_2/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" (bext) table, including column headings, from CALPOST (22 days, max)

2. Check calculated values below against CALPOST's "Ranked Daily Visibility Change" (dv) table

5. (Optional) Enter 24hr NOx conc.

YEAR	DAY	HR	RECEPTOR	COORDINATES (km)		TYPE	BEXT(Model)	BEXT(BKG)	BEXT(Total)	%CHANGE	F(RH)	bxSO4	bxNO3	bxOC	bxEC	bxPMC	bxPMF	Rank	dv(total)	dv(bkg)	Δdv	NOx(ppb)
YEAR	DAY	HR	RECEPTOR	COORDINA	TES (km)	TYPE	BEXT(Model)	BEXT(BKG)	BEXT(Total)	%CHANGE	F(RH)	bxSO4	bxNO3	bxOC	bxEC	bxPMC	bxPMF		dv(total)	dv(bkg)	Δdv	
2002	175	0	1027	1479.069	24.683	O	5.495	21.65	27.145	25.38	3.5	5.401	0.045	0.042	0.002	0.001	0.004	1	9.99	7.73	2.26	2
2002	172	0	1021	1479.244	23.778	O	4.922	21.65	26.573	22.74	3.5	4.475	0.404	0.038	0.001	0.001	0.004	2	9.77	7.72	2.05	5.5
2002	204	0	1045	1404.348	27.58	O	3.15	21.47	24.62	14.67	3.2	2.604	0.428	0.033	0.001	0.001	0.003	3	9.01	7.84	1.17	5.4
2002	353	0	1026	1492.762	24.467	O	2.594	21.29	23.884	12.18	3.3	2.017	0.557	0.058	0.002	0	0.002	4	9.71	7.60	1.5	6.7
2002	283	0	1026	1492.762	24.467	O	2.502	21.47	23.972	11.65	3.2	2.269	0.201	0.028	0.001	0.001	0.003	5	8.74	7.64	1.10	1.4
2002	195	0	1045	1404.348	27.58	O	2.011	21.83	23.841	9.21	3.7	1.983	0.031	0.015	0.001	0	0.001	6	8.88	7.51	0.88	5.4
2002	20	0	1117	1486.636	34.592	O	1.872	21.2	23.072	8.83	3	1.542	0.32	0.009	0	0	0.001	7	8.38	7.51	0.85	5.0
2002	173	0	1128	1479.259	35.042	O	1.649	21.65	23.299	7.62	3.5	1.625	0.012	0.01	0	0	0.001	8	8.46	7.72	0.73	1.2
2002	224	0	1021	1479.244	23.778	O	1.524	22.19	23.714	6.87	4.1	1.492	0.025	0.011	0	0	0.001	9	8.08	7.47	0.61	1.9
2002	298	0	1021	1479.244	23.778	O	1.459	21.47	22.929	6.8	3.2	1.204	0.16	0.014	0.001	0	0.001	10	8.38	7.54	0.56	5.3
2002	299	0	1021	1479.244	23.778	O	1.436	21.47	22.906	6.69	3.2	1.281	0.14	0.013	0	0	0.001	11	8.29	7.84	0.55	8.5
2002	275	0	1026	1492.762	24.467	O	1.27	21.47	22.74	5.92	3.2	1.202	0.058	0.009	0	0	0.001	12	8.22	7.64	0.57	5.7
2002	261	0	1045	1404.348	27.58	O	1.237	22.1	23.337	5.6	4	1.223	0.008	0.005	0	0	0.001	13	8.47	7.93	0.54	5.4
2002	252	0	1026	1492.762	24.467	O	1.189	22.1	23.289	5.38	4	1.166	0.013	0.009	0	0	0.001	14	8.46	7.93	0.52	1.5
2002	285	0	1021	1479.244	23.778	O	0.992	21.47	22.462	4.62	3.2	0.813	0.179	0.001	0	0	0	15	8.09	7.64	0.45	1.9
2002	161	0	1026	1492.762	24.467	O	0.873	21.65	22.523	4.03	3.5	0.842	0.02	0.009	0	0	0.001	16	8.12	7.73	0.40	1.7
2002	150	0	1026	1492.762	24.467	O	0.867	21.36	22.227	4.01	3.2	0.832	0.026	0.007	0	0	0.001	17	7.99	7.60	0.39	1.4
2002	340	0	1140	1401.017	37.258	O	0.817	21.29	22.107	3.84	3.1	0.663	0.153	0.001	0	0	0	18	7.93	7.56	0.38	1.8
2002	151	0	1117	1486.636	34.592	O	0.746	21.38	22.126	3.49	3.2	0.704	0.033	0.007	0	0	0.001	19	7.94	7.60	0.34	1.4
2002	160	0	1021	1479.244	23.778	O	0.735	21.65	22.385	3.4	3.5	0.71	0.014	0.01	0	0	0.001	20	8.05	7.72	0.33	1.4
2002	346	0	1021	1479.244	23.778	O	0.703	21.29	21.993	3.3	3.1	0.62	0.08	0.002	0	0	0	21	7.88	7.56	0.32	5.4
2002	247	0	1021	1479.244	23.778	O	0.661	22.1	22.761	2.99	4	0.654	0.004	0.002	0	0	0	22	8.22	7.93	0.29	0

3. Enter value of site-specific Rayleigh scattering coefficient, from "Rayleigh & Sea Salt" worksheet: 11

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

6. Enter desired NO2/NOx ratio (default is 0): 0.75

---------------------------------- OUTPUT (based on new IMPROVE algorithm) ----------------------------------

YEAR	DAY	HR	RECEPTOR	COORDINATES (km)		TYPE	BEXT(Source)	BEXT(BKG)	BEXT(Total)	%CHANGE	RH(%)	bxSO4	bxNO3	bxOC	bxEC	bxPMC	bxPMF	bxNO2	New Rank	dv(total)	dv(bkg)	Δdv
2002	175	0	1027	1479.069	24.683	O	4.936	22.04	27.016	22.58	88	4.363	0.038	0.033	0.002	0.001	0.004	0.495	1	9.94	7.90	2.03
2002	172	0	1021	1479.244	23.778	O	4.112	22.04	26.187	19.80	90	2.604	0.349	0.029	0.001	0.001	0.004	0.334	2	9.62	7.90	1.72
2002	204	0	1045	1404.348	27.58	O	2.583	21.70	24.363	11.08	84	2.076	0.257	0.026	0.001	0.001	0.003	0.399	3	8.90	7.70	1.22
2002	353	0	1026	1492.762	24.457	O	2.374	21.57	23.780	10.15	82	1.528	0.455	0.014	0.001	0	0.002	0.173	5	8.65	7.69	0.97
2002	283	0	1026	1492.762	24.467	O	2.292	21.78	24.090	10.61	84	1.752	0.167	0.022	0.001	0.001	0.002	0.347	4	8.79	7.78	1.01
2002	195	0	1045	1404.348	27.58	O	1.708	22.21	23.938	7.75	87	1.569	0.027	0.012	0.001	0	0.001	0.299	6	8.73	7.98	0.75
2002	20	0	1117	1486.636	34.592	O	1.625	21.49	23.119	7.62	83	1.16	0.28	0.007	0	0	0.001	0.398	7	8.38	7.64	0.73
2002	173	0	1128	1479.259	35.042	O	1.613	22.04	23.657	7.37	90	1.297	0.01	0.008	0	0	0.001	0.297	8	8.61	7.90	0.71
2002	224	0	1021	1479.244	23.778	O	1.546	22.64	24.193	6.87	93	1.218	0.028	0.009	0	0	0.001	0.297	9	8.83	8.17	0.66
2002	298	0	1021	1479.244	23.778	O	1.209	21.78	22.990	5.58	84	0.988	0.132	0.011	0.001	0	0.001	0.074	13	8.32	7.78	0.54
2002	299	0	1021	1479.244	23.778	O	1.237	21.78	23.027	5.72	84	0.986	0.217	0.01	0	0	0.001	0.124	12	8.34	7.78	0.56
2002	275	0	1026	1492.762	24.467	O	1.164	21.79	22.943	5.34	84	0.956	0.049	0.007	0	0	0.001	0.173	14	8.30	7.78	0.52
2002	261	0	1045	1404.348	27.58	O	1.137	22.64	23.783	5.06	88	1.026	0.007	0.004	0	0	0.001	0.099	16	8.66	8.17	0.49
2002	252	0	1026	1492.762	24.467	O	1.369	22.64	24.015	6.05	89	0.978	0.012	0.027	0	0	0.001	0.371	10	8.76	8.17	0.59
2002	285	0	1021	1479.244	23.778	O	1.346	21.78	23.081	6.74	84	0.626	0.549	8E-04	0	0	0	0.47	11	8.34	7.78	0.56
2002	161	0	1026	1492.762	24.467	O	1.116	22.04	23.165	5.06	86	0.67	0.017	0.007	0	0	0.001	0.421	15	8.40	7.90	0.50
2002	150	0	1026	1492.762	24.467	O	0.997	21.67	22.668	4.62	83	0.622	0.021	0.005	0	0	0.001	0.347	18	8.18	7.73	0.46
2002	340	0	1140	1401.017	37.258	O	1.071	21.57	22.646	4.99	82	0.5	0.125	8E-04	0	0	0	0.446	17	8.17	7.69	0.49
2002	151	0	1117	1486.636	34.592	O	0.913	21.67	22.584	4.24	81	0.539	0.027	0.003	0	0	0.001	0.347	20	8.15	7.73	0.42
2002	160	0	1021	1479.244	23.778	O	0.938	22.04	22.980	4.26	90	0.565	0.013	0.008	0	0	0.001	0.347	19	8.32	7.90	0.42
2002	346	0	1021	1479.244	23.778	O	0.633	21.57	22.200	2.95	82	0.467	0.065	0.002	0	0	0	0.099	21	7.98	7.69	0.29
2002	247	0	1021	1479.244	23.778	O	0.553	22.64	23.195	2.46	93	0.548	0.004	0.002	0	0	0	0	22	8.41	8.17	0.24

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

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

where

$$[large\ sulfate_T] = \{[S_T]/20\} \bullet [S_T] \text{ if } [S_T] < 20\ \mu g^3$$

$$[large\ sulfate_T] = [S_T] \text{ if } [S_T] \geq 20\ \mu g/m^3 \qquad \text{(Eqs. A-2)}$$

$$[small\ sulfate_T] = [S_T] - [large\ sulfate_T],$$

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

$$[large\ sulfate_N] = \{[S_N]/20\} \bullet [S_N] \text{ if } [S_N] < 20\ \mu g^3$$

$$[large\ sulfate_N] = [S_N] \text{ if } [S_N] \geq 20\ \mu g/m^3 \qquad \text{(Eqs. A-3)}$$

$$[small\ sulfate_N] = [S_N] - [large\ sulfate_N],$$

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,

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

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

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

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 E

US Steel Four-Factor Analysis Submittal

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United States Steel Corporation
Gary Works
One North Broadway
Gary, IN 46402-3199

September 30, 2020

Via Electronic Mail
Jean Boling
Indiana Department of Environmental Management
Office of Air Quality, Programs Branch
JBoling@idem.in.gov

Subject: U. S. Steel - Gary Works Four-Factor Analysis
Re: Regional Haze State Implementation Plan – Second Planning Period – Request for Four-Factor Analysis

Dear Ms. Boling:

On June 18, 2020, the Indiana Department of Environmental Management (IDEM) notified U. S. Steel – Gary Works that it was a selected source for the second implementation period four-factor analysis for the Regional Haze State Implementation Plan (SIP) and requested U. S. Steel – Gary Works to submit a Four-Factor Analysis. The request included evaluations of the No. 3 Sinter Plant sinter strands (NOx and SO2), the No. 14 Blast Furnace (NOx and SO2), and the 84" Hot Strip Mill Reheat Furnaces and Waste Heat Boilers (NOx). The requested Four-Factor Analysis report is attached for your review.

Any questions regarding this notification can be directed to Marrissa Taylor at (219) 888-7938.

Sincerely,

Alexis Piscitelli
Senior Director, Environmental Control
United States Steel Corporation

BARR

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

- ***No. 3 Sinter Plant Sinter Strands***
- ***No. 14 Blast Furnace Stoves and Casthouse***
- ***84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4 and Waste Heat Boilers No. 1 and No. 2***

Prepared for
United States Steel Corporation
Gary Works Facility

September 25, 2020

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Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

September 25, 2020

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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
BACT	best available control technology
BART	best available retrofit technology
CEPCI	Chemical Engineering Plant Cost Index
dv	deciview
EGU	Electric Generating Unit
EPA	U.S. Environmental Protection Agency
Gary Works	U. S. Steel Gary Works
IDEM	Indiana Department of Environmental Management
IMPROVE	Interagency Monitoring of Protected Visual Environments
km	kilometer
LAER	lowest achievable emission rate
lb	pounds
LNB	Low-NO_X Burners
Mammoth Cave	Mammoth Cave National Park
Mingo	Mingo National Wildlife Refuge
MMBtu	million British Thermal Units
MMscf	million standard cubic feet
NO_X	nitrogen oxides
O&M	operating and maintenance
PM	particulate matter
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
VOC	volatile organic compound

1 Executive Summary

In accordance with the Indiana Department of Environmental Management's (IDEM's) June 18, 2020 Request for Information (RFI) Letter,[1] U. S. Steel Gary Works (Gary Works) evaluated potential emission control measures for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) for the No. 3 Sinter Plant Sinter Strands (ISS10379 and ISS30381) and No. 14 Blast Furnace (IDST0359 and IDBF0369), and for NO_X emissions from the 84" Hot Strip Mill Reheat Furnaces and Waste Heat Boilers (RB1B0508, RB2B0509, RMF10500, RMF20501, RMF30502, and RMF40503). 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) RHR State Implementation Plan (SIP) guidance[2] 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, evaluating effective emission control measures, and conducting the review of the four statutory factors. Additionally, this analysis evaluates the visibility benefits at the associated Class I areas from the installation of potential emission control measures, consistent with the 2019 RH SIP Guidance.

The NO_X and SO_2 four-factor analyses with visibility benefits evaluations conclusions are summarized in Table 1-1 and Table 1-2, respectively.

As described in Section 3 and Section 4, the No. 3 Sinter Plant Sinter Strands and No. 14 Blast Furnace (Stoves and Casthouse) four-factor analyses with visibility benefits evaluations concluded that:

- There is no reasonable set of NO_X and SO_2 emission control measures beyond what is currently installed and operated for these emission units (see Sections 3.1.1, 3.2.1, 4.1.1, and 4.2.1).
- The existing emission control measures are equivalent to those determined to be the Best Available Control Technology (BACT) in a recent BACT analysis and, therefore, are considered effective emission controls (see Sections 3.1.1, 3.2.1, 4.1.1, and 4.2.1).

[1] June 18, 2020 letter from Mathew Stuckey of IDEM to Marrissa Taylor of U. S. Steel Gary Works.

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

- Additional NO_X and SO_2 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) and Seney National Wildlife Refuge (Seney)), or trending towards (Mingo National Wildlife Refuge (Mingo)), the 2028 uniform rate of progress (URP) (see Section 6.1),
    - The trajectory analysis demonstrates that Gary Works does not appreciably contribute to visibility impairment to the Class I areas on the most impaired days at the monitors and, therefore, any installation of additional emission control measures at Gary Works will not appreciably improve visibility in these Class I areas (see Section 6.2).
- Therefore, the No. 3 Sinter Plant Sinter Strands and No. 14 Blast Furnace (Stoves and Casthouse) existing NO_X and SO_2 emission performance are appropriate and sufficient for the IDEM's regional haze reasonable progress goal (see Sections 3.1.8, 3.2.8, 4.1.8, and 4.2.8).

As described in Section 5, the 84" Hot Strip Mill Reheat Furnaces and Waste Heat Boilers NO_X four-factor analysis with visibility benefits evaluation concluded that:

- The reasonable set of NO_X emission control measures beyond what is currently installed and operated for these emission units consists of Low-NO_X Burners (LNB) (see Section 5.1.1).
- LNB installation on the 84" Hot Strip Mill Reheat Furnaces and Waste Heat Boilers are not cost-effective, based on the associated cost-effectiveness values ($ per ton of emissions reduction). Furthermore, the additional capital and operating costs may negatively impact Gary Works' ability to compete in the economic market (see Section 5.1.3).
- Independent of the cost-effectiveness evaluation, which alone indicates that no additional emission control measures are necessary and appropriate, the additional NO_X emission control measures and their associated NO_X emission reductions are also not necessary and appropriate for Gary Works 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 and Seney), or trending towards (Mingo), the 2028 URP (see Section 6.1),
    - The trajectory analysis demonstrates that Gary Works does not appreciably contribute to visibility impairment to the Class I areas on the most impaired days at the monitors (see Section 6.2), and
    - Thus, the NO_x emission reduction associated with LNB installation on the 84" Hot Strip Mill Reheat Furnaces and Waste Heat Boilers does not justify the associated cost, as described in Section 5.1.3, because the emission control measure will not appreciably improve visibility in these Class I areas (see Section 5.1.7).
- Therefore, the 84" Hot Strip Mill Reheat Furnaces and Waste Heat Boilers existing NO_X emission performance are appropriate and sufficient for the IDEM's regional haze reasonable progress goal (see Section 5.1.8).

In addition to the four statutory factors, this analysis also considers the current visibility and the potential visibility benefits from installing additional emission control measures on the associated sources at the facility. An analysis of current visibility conditions was completed at the three Class I areas closest to Gary Work's facility (~500-570 km away): Mammoth Cave in Kentucky, Seney in northern Michigan and Mingo in Missouri. 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 (Mammoth Cave and Seney), or trending towards (Mingo), the 2028 URP. Thus, it is not necessary for Gary Works to install additional emission control measures to make reasonable progress at these distant Class I areas and, as shown below, any reductions in emissions at Gary Works will not appreciably improve visibility in these Class I areas.

Furthermore, a reverse particle trajectory analysis was completed from these same Class I areas (Mammoth Cave, Mingo, and Seney) to determine how emissions from Gary Works could impact visibility in Class I areas on the 20% most impaired days. As shown in Section 6.1, the majority (97.5%) of the most impaired trajectories are not traveling from the general direction of Gary Works. Furthermore, most of the 48-hour reverse trajectories end before reaching the Gary Works facility location, indicating that the nearest Class I areas are at a distance far enough away from the facility, and therefore Gary Works is not reasonably expected to contribute to visibility impairment at the Class I areas. This information generally demonstrates sources from other regions, and not Gary Works, are contributing to the visibility impairment on the most impaired days at the monitors. For example, the emissions are likely coming from other metropolitan areas such as Louisville, St. Louis, Indianapolis, Columbus, Cincinnati, and Nashville. As such, the installation of additional emission control measures at Gary Works would not improve visibility in these Class I areas on the most impaired days.

Lastly, additional emission control measures could impact the economic viability of the company to continue to operate in competitive economic markets. Gary Works, as well as the entire integrated iron and steel mill industry, is highly sensitive to incremental capital and operating costs due to substantial fluctuation in global economic markets. Considering the current visibility progress and that Gary Works does not appreciably contribute to the associated visibility impairment at the pertinent Class I areas, any additional emission control measures that would be a substantial barrier for the facility to continue to operate would be unreasonable and inappropriate.

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

Reasonable Set of Emission Control Measures	Factor #1 – Cost of Compliance	Factor #2 – Time Necessary for Compliance	Factor #3 – Energy and Non-Air Quality Environmental Impacts of Compliance	Factor #4 – Remaining Useful Life of the Source	Visibility Benefits	Does this Analysis Support the Installation of this Emission Control Measure?
No. 3 Sinter Plant Sinter Stands						
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.
No. 14 Blast Furnace Stoves						
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.
No. 14 Blast Furnace Casthouse						
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.
84" Strip Mill Reheat Furnaces No. 1 through No. 4						
Low-NO_X Burners (LNB)	$14,100 per ton of NO_X removed	2-3 years after SIP promulgation.	Negligible energy and non-air quality environmental impacts	20-year control equipment life	Emissions reductions at Gary Works would not improve visibility at Class I areas of interest on the most impaired days.	No – LNB are not cost-effective and would not improve the visibility at the associated Class I areas of interest on the most impaired days.

Reasonable Set of Emission Control Measures	Factor #1 – Cost of Compliance	Factor #2 – Time Necessary for Compliance	Factor #3 – Energy and Non-Air Quality Environmental Impacts of Compliance	Factor #4 – Remaining Useful Life of the Source	Visibility Benefits	Does this Analysis Support the Installation of this Emission Control Measure?
Waste Heat Boiler No. 1						
Low-NO_X Burners (LNB)	$6,100 per ton of NO_X removed	2-3 years after SIP promulgation.	Negligible energy and non-air quality environmental impacts	20-year control equipment life	Emissions reductions at Gary Works would not improve visibility at Class I areas of interest on the most impaired days.	No – LNB are not cost-effective and would not improve the visibility at the associated Class I areas of interest on the most impaired days.
Waste Heat Boiler No. 2						
Low-NO_X Burners (LNB)	$6,300 per ton of NO_X removed	2-3 years after SIP promulgation.	Negligible energy and non-air quality environmental impacts	20-year control equipment life	Emissions reductions at Gary Works would not improve visibility at Class I areas of interest on the most impaired days.	No – LNB are not cost-effective and would not improve the visibility at the associated Class I areas of interest on the most impaired days.

Table 1-2 Summary of SO_2 Four-Factor Analyses with Visibility Benefits Evaluations

Reasonable Set of Emission Control Measures	Factor #1 – Cost of Compliance	Factor #2 – Time Necessary for Compliance	Factor #3 – Energy and Non-Air Quality Environmental Impacts of Compliance	Factor #4 – Remaining Useful Life of the Source	Visibility Benefits	Does this Analysis Support the Installation of this Emission Control Measure?
No. 3 Sinter Plant Sinter Stands						
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.
No. 14 Blast Furnace Stoves						
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.
No. 14 Blast Furnace Casthouse						
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

Section 2.1 discusses the RFI provided to Gary Works 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 20-year facility-wide NO_X and SO_2 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 included best available retrofit technology (BART) analyses for 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 Gary Works on June 18, 2020. The RFI stated 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 SO_2 and NO_X that react with available ammonia. The RFI stated that IDEM's source selection rankings identified iron and steel mills as one of the source categories for analysis of emission control measures based on rudimentary estimates of Q/d, or emissions divided by distance from the parks which do not account for meteorological conditions or other site-specific data. Based upon the rudimentary Q/d criterion that does not account for many factors, including meteorological data, IDEM requested that Gary Works submit a four-factor analysis evaluating potential emission control measures, pursuant to 40 CFR 51.308(f)(2)(i),[3] by September 30, 2020 for the emission units identified in Table 2-1.

[3] The four statutory factors are 1) cost of compliance, 2) time necessary for compliance, 3) energy and non-air quality environmental impacts of compliance, and 4) remaining useful life of the source.

Table 2-1 Identified Emission Units

Unit	Unit ID	Applicable Pollutants
No. 3 Sinter Plant Sinter Strands	ISS10379	NO_X, SO_2
	ISS30381	
No. 14 Blast Furnace Stoves	IDST0359	NO_X, SO_2
No. 14 Blast Furnace Casthouse	IDBF0369	NO_X, SO_2
Waste Heat Boiler No. 1	RB1B0508	NO_X
Waste Heat Boiler No. 2	RB2B0509	NO_X
Reheat Furnace No. 1 (84" Hot Strip Mill Furnace)	RMF10500	NO_X
Reheat Furnace No. 2 (84" Hot Strip Mill Furnace)	RMF20501	NO_X
Reheat Furnace No. 3 (84" Hot Strip Mill Furnace)	RMF30502	NO_X
Reheat Furnace No. 4 (84" Hot Strip Mill Furnace)	RMF40503	NO_X

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 visibility benefits at the associated Class I areas 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 evaluation factors as detailed in the 2019 RH SIP guidance.

2.1.1.1 Identifying Available Emission Control Measures

The identification of emission control measures for NO_X and SO_2 are discussed in Sections 3.1, 3.2, 4.1, 4.2, and 5.1. The approach that was used to identify the emission control measures is described in Section 2.1.1.1.1 and Section 2.1.1.1.2.

2.1.1.1.1 Evaluating the Reasonable Set of Emission Control Measures

The 2019 RH SIP Guidance states that the first step of the analysis is to identify the technically feasible control options.[4] However, EPA recognizes that "there is no statutory or regulatory requirement to consider all technically feasible measures or any particular measures,"[5] and states that "a range of technically feasible measures available to reduce emissions would be one way to justify a reasonable set."[6] Emission control measures may include both physical and operational changes. Once all technically feasible emission control measures are identified, Gary Works justifies which emission control measures were considered against the four factors (reasonable set).

In order to be considered technically feasible, an emission control measure must have been previously installed and operated successfully on a similar source under similar physical and operating conditions. Novel 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 iron and steel mills.

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

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

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 was provided in the BACT evaluation for Nucor Steel Louisiana[7] (2010 Nucor BACT). A summary of the RBLC data reviewed is provided in Appendix A.
2. Review air permits for similar sources to identify emission control measures and emission limits, which are being used in practice; a comparison of air permits from similar facilities is provided in Appendix B.

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[4] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003., Page 28.

[5] Ibid, Page 29.

[6] Ibid.

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

3. Review the 2010 Nucor BACT[8] analysis, which provides additional detail regarding specific control technologies that were considered technically feasible and descriptions of why certain technologies were not considered technically feasible.
4. Select the reasonable set of emission control measures, 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 Gary Works facility (i.e., sinter plant, blast furnace, and hot strip mill) to review potential emission control measures, discuss technical feasibility, and compare the physical configuration of existing equipment to that required for additional emission control measures.

This approach to establish the reasonable set of emission control measures is appropriate and justified because:

1. It is consistent with the 2019 RH guidance (see the discussion above), and
2. The current visibility status does not warrant a more stringent emission control measure selection approach because:
    a. The 5-year average visibility impairment on the most impaired days at the associated Class I areas of interest is already below (Mammoth Cave and Seney), or trending towards (Mingo), the 2028 URP (see Section 6.1),
    b. The trajectory analysis demonstrates that sources from other regions, and not Gary Works, are contributing to the visibility on the most impaired days at the monitors (see Section 6.2), and
    c. Because Gary Works does not appreciably contribute to visibility impairment of the Class I areas, the installation of additional emission control measures at Gary Works will not appreciably improve visibility in the associated Class I areas on the most impaired days (see Section 6.2).

2.1.1.1.2 Evaluating Effective Emission Control Technology

The 2019 RH SIP Guidance identified eight example scenarios and described the associated rationale for when sources should be considered to already have effective emission control technology in place and, therefore, states could exclude these sources from needing to complete a four-factor analysis.[9] The Guidance includes a list of eight potential scenarios for which EPA believes the source could be

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[8] On page 23 of the 2019 RH SIP Guidance, EPA recognized that the "statutory considerations for selection of BACT and LAER are also similar to, if not more stringent than, the four statutory factors for reasonable progress."

[9] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003., Page 22.

considered effectively controlled. In addition, EPA clarified that the associated scenarios are not an exhaustive list; they are merely to illustrate examples for the state to consider.[10]

One of the example scenarios of a source which has effective emission control technology is for sources that underwent a BACT or Lowest Achievable Emission Rate (LAER) analysis for visibility impairing pollutants (SO_2 and NO_X) after July 31, 2013. EPA notes that the BACT and LAER control equipment review methodologies are "similar to, if not more stringent than, the four statutory factors for reasonable progress."[11]

Barr assumes that states could justify that a source has effective controls with a BACT or LAER determination from before July 31, 2013, if the current control measures are equivalent or sufficiently similar to the control measures for similar sources that did undergo a BACT or LAER review.

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) [12] unless more refined site-specific estimates are available. Under this step, the annualized cost of installation and operation on a dollars per ton of pollutant removed ($/ton) of the 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."[13]

Generally, if the average cost-effectiveness is greater than the threshold and/or there is no expected visibility improvement, 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 visibility improvements are expected, then the cost is considered reasonable *for purposes of Factor #1,* pending an evaluation of whether the absolute cost of control (i.e., costs in absolute dollars, not normalized to $/ton) is unreasonable. This situation is particularly applicable to a source with existing emission control measures

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[10] Ibid, Page 23.

[11] Ibid.

[12] 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.

[13] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, Page 37.

with an intermediate or high degree of effectiveness, as is the case for the No. 3 Sinter Plant Sinter Strands due to their existing SO_2 emission control measures (see Section 2.2.1 for additional information).

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 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.

There is not an applicable and appropriate cost-effectiveness threshold because installation of additional emission control measures at Gary Works would not improve visibility at the associated Class I areas (as described in Section 6).

2.1.1.3 Factor 2 – Time Necessary for Compliance

Factor #2 considers the time needed for Gary Works 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 SO_2 emission control measure requires a unit outage as part of its installation, Gary Works considers the forecasted outage schedule for the associated units in conjunction with the expected timeframe for engineering and equipment procurement following any necessary permitting through IDEM and EPA for 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 facility permanently ceases operation. Generally, the remaining useful life of the source is assumed to be longer than the useful life of the emission control measure unless the source is under an enforceable requirement to cease operation. In the presence of an enforceable end date, the cost calculation can use a shorter period to amortize the capital cost.

For the 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.

2.1.1.6 Visibility Benefits

In addition to the four statutory factors, this analysis considers the potential visibility benefits from installing additional emission reduction 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."[14]

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 and Seney), or trending towards (Mingo), the 2028 URP,
2. The facility is shown not to appreciably impact the associated Class I areas 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

Gary Works is an integrated iron and steel mill located in Gary, Indiana. Operations include raw material handling, sintering, ironmaking, steelmaking, and manufacturing of steel slabs, hot rolled, cold rolled, and tin mill products, as well as on-site utility generation. The three emission unit groups addressed in IDEM's RFI are described below.

2.2.1 No. 3 Sinter Plant Sinter Strands

The No. 3 Sinter Plant agglomerates iron bearing and other materials from various sources to create a raw material feedstock for the blast furnaces that supplements iron ore pellets. The sinter feedstock is thoroughly blended and combusted on each sinter strand by drawing air through the sintered material and into the windboxes. The windboxes exhaust fumes through the two existing control trains which control particulate matter (PM) and SO_2 emissions. Each train consists of reheat burners, cyclones, a

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[14] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, Page 34.

quench reactor, a dry venturi scrubber, and a baghouse. Sintered material is then cooled, sized, and screened, so that on-spec material is sent to the blast furnaces.

Along the traveling grate, the iron ore fines, coke breeze, and other materials are ignited with natural gas burners. The NOx emissions are generated from the associated combustion of the coke and natural gas and the combustion of natural gas at the reheat burners. The No. 3 Sinter Plant Sinter Strands follow good combustion practices.

The No. 3 Sinter Plant Sinter Strands generate SO_2 emissions through oxidation of sulfur compounds present in the raw materials (iron ore, coke, etc.) and natural gas fuel. Figure 2-1 presents a simplified version of the existing emission control measures for the No. 3 Sinter Plant windbox exhaust. The exhaust treatment reduces PM and SO_2 emissions.

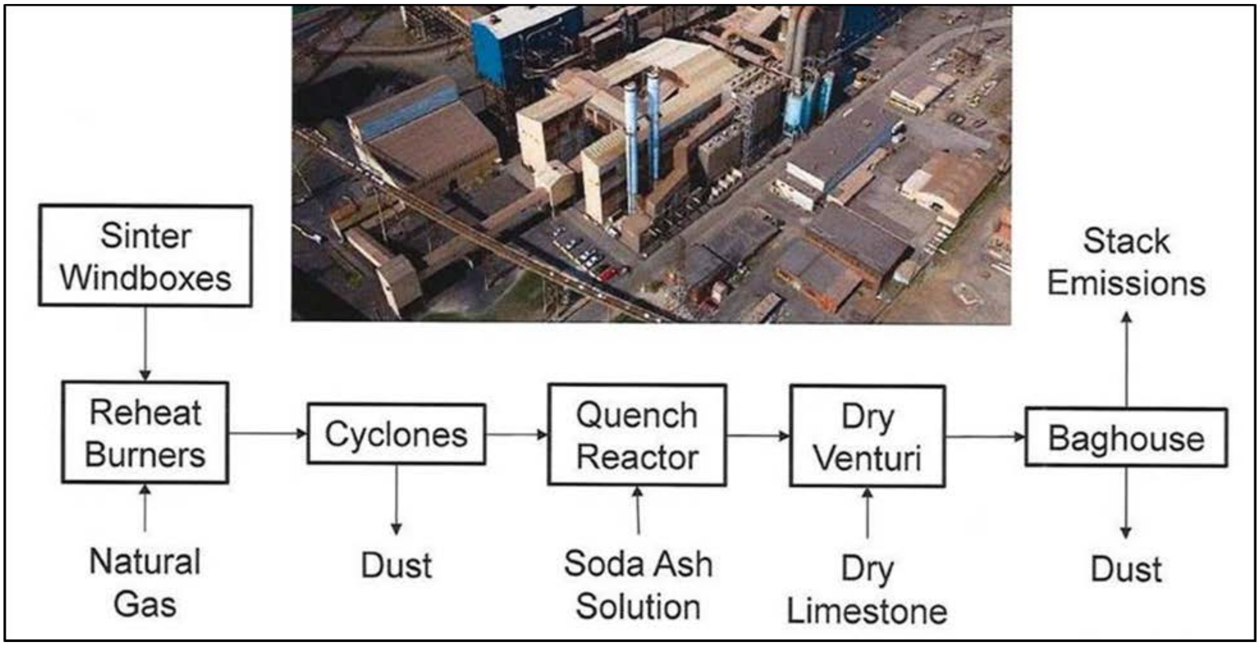

Figure 2-1 No. 3 Sinter Plant Windbox Exhaust Treatment

The exhaust gas from the sinter windbox is processed through five main stages before exiting the stack. First, the exhaust gas passes through reheat burners ensure that the temperature remains above the acid dew point to help prevent corrosion in downstream control equipment and to prepare the gas for downstream contact with the soda ash solution. The cyclones remove fine PM from the exhaust gas stream. The quench reactor sprays a soda ash solution to cool the hot exhaust gas stream and to react with and absorb SO_2. The dry venturi scrubber with dry limestone addition allows for further removal of the SO_2 through reaction with the limestone. Finally, the exhaust gas (also containing any excess dry limestone as well as dry reaction products) is processed through a baghouse to reduce PM before ultimately being discharged to the atmosphere from the stack.

The original control system, an electrodynamic venturi scrubber, was replaced in 1996. After startup, the facility worked to optimize the design and performance of the system through 2003 in order to achieve significant emission reductions over the previous technology.

2.2.2 No. 14 Blast Furnace (Stoves and Casthouse)

The blast furnace combines coke, limestone, sinter, iron ore pellets, and other iron sources with high heat to produce pig iron and slag. To produce this high amount of heat, 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 and supplemental natural gas to heat fresh air for injection. The blast furnace is also able to inject pulverized coal and natural gas. Blast furnace gas is the partially combusted, CO-rich gas that is produced within the blast furnace itself. This gas has a low but beneficial heating value and is cleaned for PM via the integrated scrubbing system prior to combustion as a fuel source to reduce consumption of natural resources and improve energy efficiency.

Once the pig iron and slag are produced in the No. 14 Blast Furnace, they flow through a series of troughs which empty the molten iron into a submarine car for transfer and empty the slag into the adjacent slag pit or slag granulation facility.

The No. 14 Blast Furnace Stoves resulting NO_X emissions are generated from primarily firing BFG and supplemental natural gas (to maintain flame temperature) to heat fresh air for injection. BFG is considered a low-NO_X fuel because it generates less than half of the NO_X per unit of energy as natural gas. BFG burns at a cooler temperature, which prevents the majority of thermal NO_X formation when compared to natural gas combustion. Therefore, the use of BFG in the No. 14 Blast Furnace Stoves is an existing NO_X emission control measure.

The NOx emissions from the No. 14 Blast Furnace Casthouse are not significant (28.98 ton NO_X per year in 2019). The NO_X emissions may be released during the casting process and are fugitive in nature (i.e., not emitted from a stack).

The No. 14 Blast Furnace Stoves generate SO_2 emissions through oxidation of sulfur compounds present in the fuel (blast furnace gas and natural gas). Blast furnace gas and natural gas are considered low sulfur fuels compared to other solid and liquid fuels and are utilized as SO_2 emission control measures.

The No. 14 Blast Furnace Casthouse’s molten iron and slag streams contain sulfur and sulfur compounds that form SO_2 upon contacting air during the casting process and are fugitive in nature (i.e., not emitted from a stack).

2.2.3 84” Hot Strip Mill Reheat Furnaces and Waste Heat Boilers

The 84” Hot Strip Mill Reheat Furnaces are used to heat incoming steel slabs to working temperatures to be rolled into steel coils. These reheat furnaces fire natural gas and route their exhausts towards the waste boilers to recoup thermal energy.

The No. 1 and No. 2 Waste Heat Boilers produce utility steam for use throughout the Gary Works facility. The boilers are natural gas-fired, but also make use of hot exhaust from the stacks of the 84" Hot Strip Mill Reheat Furnaces to reduce heating input requirements. These boilers increase efficiency by using recouped heat from the reheat furnaces.

The 84" Hot Strip Mill Reheat Furnaces and Waste Heat Boilers generate NO_X emissions from natural gas combustion. The units implement good combustion practices as a NO_X emission control measure. In addition, the 84" Hot Strip Mill Reheat Furnaces operate John Zink Hamworthy's ZoloSCAN technology, which is a laser-based combustion diagnostic system, that allows for better process control (temperature, O_2, CO and water) and results in actual NO_X emission reductions from fuel savings and minimizing excess air.[15]

2.3 20-year Facility-wide NO_X and SO_2 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, Gary Works has achieved substantial facility-wide NO_X and SO_2 emission reductions in the last twenty years as a result of extensive projects, including the installation of SO_2 emission control measures on the No. 3 Sinter Plant Sinter Strand and shutting down three Coke Battery units. Figure 2-2 presents the facility-wide NO_X and SO_2 emissions from 2000 to 2019. Since Gary Works has already reduced facility-wide NO_X and SO_2 emissions by 58% from 2000 (2000 = 11,557 tons/year NO_X and SO_2, 2019 = 4,887 tons/year NO_X and SO_2), additional emission control measures are imprudent and unnecessary to achieve the Regional Haze goal when considered in conjunction with the current visibility trends (see Section 6.1) and the visibility impacts at the associated Class I areas from Gary Works (see Section 6.2).

[15] https://www.johnzinkhamworthy.com/wp-content/uploads/steel-reheat-combustion-monitoring.pdf

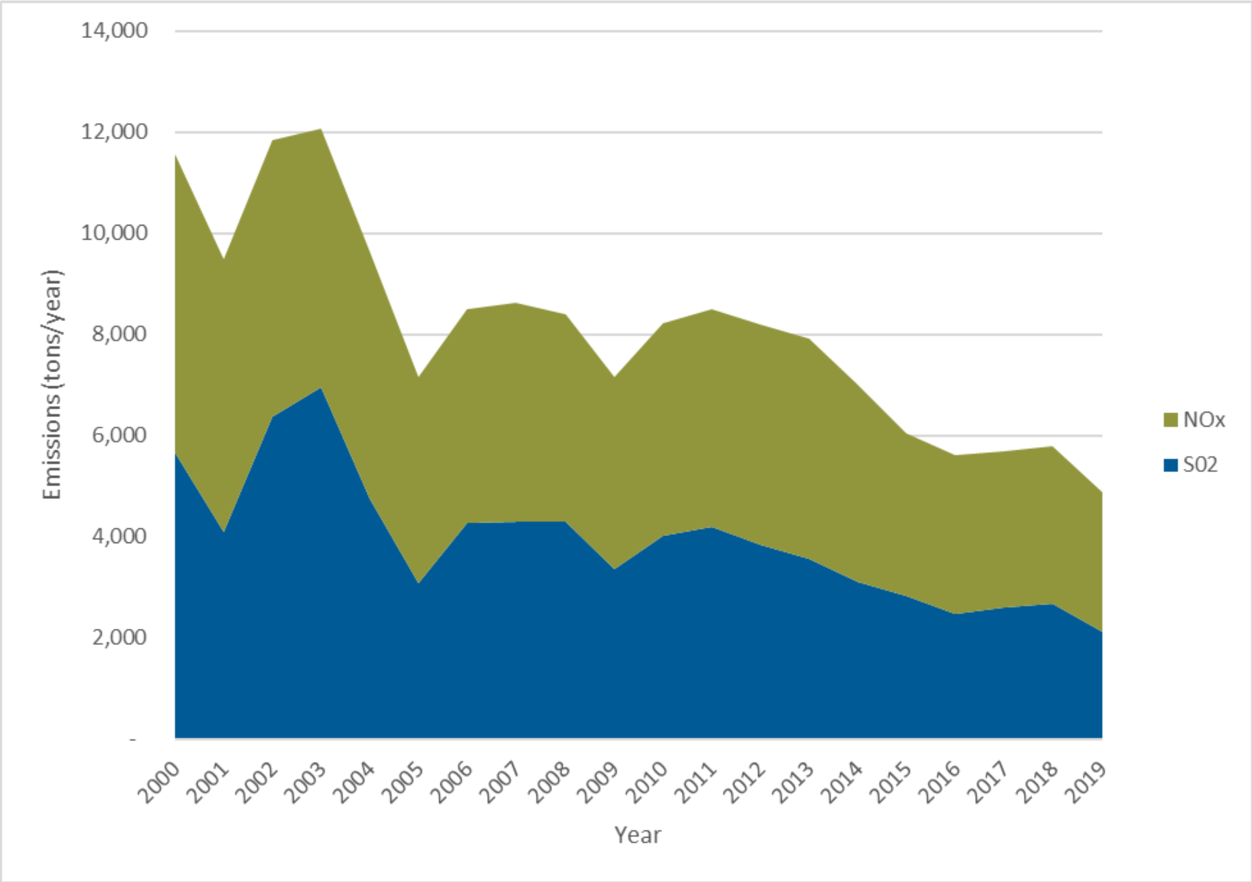

Figure 2-2 Facility-wide NO_X and SO_2 Emissions from 2000 to 2019

3 No. 3 Sinter Plant Sinter Strands

The following sections describe the analysis for NO_X and SO_2 emission control measures for the No. 3 Sinter Plant Sinter Strands.

3.1 Four-Factor Analysis – NO_X

The following sections describe the four-factor analysis with visibility benefits evaluation for determining the reasonable set of NO_X emission control measures (Section 3.1.1), the evaluation factors (Sections 3.1.3 through 3.1.7), and the proposed emission control measures (Section 3.1.8) for No. 3 Sinter Plant Sinter Strands.

3.1.1 NO_X Emission Control Measures

Table 3-1 presents NO_X emission control measures for sinter plants at similar sources, as represented in the RBLC (Appendix A) and their respective air permits (Appendix B).

Table 3-1 Sinter Plant NO_X Emission Control Measures at Similar Sources

Facility	Emission Unit Description	NO_X Emission Control Measure(s)
ArcelorMittal Indiana Harbor East	Sinter Plant	None
ArcelorMittal Indiana Harbor West(1)	Sinter Plant	None
ArcelorMittal Burns Harbor	Continuous Sintering Process Plant	None
Nucor St. James(2) (2010 Nucor BACT)	Sinter Plant	None

(1) The sinter plant at ArcelorMittal Indiana Harbor West is no longer included in the facility's most recently issued Title V permit.
(2) The sinter plant at Nucor St. James has not been constructed.

There are no additional NO_X emission control measures based on the 2010 Nucor BACT and emission control measures described in the RBLC (Appendix A) and air permits for similar sources (Appendix B). As such, the No. 3 Sinter Plant Sinter Strands have no reasonable set of NO_X emission control measures beyond what is currently installed and operated for these emission units. Furthermore, the existing NO_X emission control measures are equivalent to those determined to be BACT in the 2010 Nucor BACT and, therefore, are considered effective emission controls.

3.1.2 Baseline Emission Rates

Since the four-factor analysis concluded the No. 3 Sinter Plant Sinter Strands 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 the No. 3 Sinter Plant Sinter Strands 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. Even in the circumstance where there was an emission control measure identified as part of the reasonable set, the associated emission control measure's cost-effectiveness would not be reasonable because the emission reduction technology would not impact visibility at the associated Class I areas (see Section 6).

3.1.4 Factor 2 – Time Necessary for Compliance

Since the four-factor analysis concluded the No. 3 Sinter Plant Sinter Strands 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 the No. 3 Sinter Plant Sinter Strands 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 the No. 3 Sinter Plant Sinter Strands 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 the No. 3 Sinter Plant Sinter Strands 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. However, as described in Section 6, additional NO_X emission reductions are not appropriate and are unnecessary for Gary Works 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 and Seney), or trending towards (Mingo), the 2028 URP (see Section 6.1),
2. The trajectory analysis demonstrates that Gary Works does not appreciably contribute to visibility impairment to the Class I areas on the most impaired days at the monitors (see Section 6.2), and
3. Any installation of additional emission control measures at Gary Works will not appreciably improve visibility in these Class I areas (see Section 6.2).

3.1.8 Proposed NO_X Emission Control Measures

The four-factor analysis with visibility benefits evaluation concluded that additional NO_X emission control measures at the No. 3 Sinter Plant Sinter Strands beyond those described in Section 2.2.1 are not required to make reasonable progress in reducing NO_X emissions. As such, Gary Works proposes to maintain the existing NO_X emission control measures.

3.2 Four-Factor Analysis – SO_2

The following sections describe the four-factor analysis with visibility benefits evaluation for determining the reasonable set of SO_2 emission control measures (Section 3.2.1), the evaluation factors (Sections 3.2.3 through 3.2.7), and the proposed emission control measures (Section 3.2.8) for No. 3 Sinter Plant Sinter Strands.

3.2.1 SO_2 Emission Control Measures

As described in Section 2.2.1, the No. 3 Sinter Plant Sinter Strand already utilizes a windbox exhaust treatment system, including a quench reactor and dry lime scrubber, as post-combustion SO_2 emission control measures. Table 3-2 presents SO_2 emission control measures for sinter plants at similar sources, as represented in the RBLC (Appendix A) and their respective air permits (Appendix B).

Table 3-2 Sinter Plant SO_2 Emission Control Measures at Similar Sources

Facility	Emission Unit Description	SO_2 Emission Control Measure(s)
ArcelorMittal Indiana Harbor East	Sinter Plant	None
ArcelorMittal Indiana Harbor West(1)	Sinter Plant	Wet venturi scrubbers
ArcelorMittal Burns Harbor	Continuous Sintering Process Plant	Venturi scrubber
Nucor St. James(2) (2010 Nucor BACT)	Sinter Plant	Lime spray dry scrubber Dry sorbent injection(3)

(1) The sinter plant at ArcelorMittal Indiana Harbor West is no longer included in the facility's most recently issued Title V permit.
(2) The sinter plant at Nucor St. James has not been constructed.
(3) The 2010 Nucor BACT identified dry sorbent injection as technically feasible but was listed as a lower control efficiency than a lime spray dry scrubber.

A wet scrubber system has functionally equivalent SO_2 control performance compared to the existing quench reactor with dry-lime scrubber at Gary Works' sinter plant; therefore, a wet scrubber system does not represent additional SO_2 emission reduction potential compared to the existing system. A wet scrubber system is not evaluated further.

There are no additional SO_2 emission control measures because the existing SO_2 emission control measures represent the best SO_2 emission reduction potential based on the 2010 Nucor BACT and emission control measures described in the RBLC (Appendix A) and air permits for similar sources

(Appendix B). As such, the No. 3 Sinter Plant Sinter Strands have no reasonable set of SO_2 emission control measures. Furthermore, the existing SO_2 emission control measures are equivalent to those determined to be BACT in the 2010 Nucor BACT and, therefore, are considered effective emission controls.

3.2.2 Baseline Emission Rates

Since the four-factor analysis concluded the No. 3 Sinter Plant Sinter Strands have no reasonable set of SO_2 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.

3.2.3 Factor 1 – Cost of Compliance

Since the four-factor analysis concluded the No. 3 Sinter Plant Sinter Strands have no reasonable set of SO_2 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 SO_2 emission control measures. Even in the circumstance where there was an emission control measure identified as part of the reasonable set, the associated emission control measure's cost-effectiveness would not be reasonable because the emission reduction technology would not impact visibility at the associated Class I areas (see Section 6).

3.2.4 Factor 2 – Time Necessary for Compliance

Since the four-factor analysis concluded the No. 3 Sinter Plant Sinter Strands have no reasonable set of SO_2 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 SO_2 emission control measures.

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

Since the four-factor analysis concluded the No. 3 Sinter Plant Sinter Strands have no reasonable set of SO_2 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 SO_2 emission control measures.

3.2.6 Factor 4 – Remaining Useful Life of the Source

Since the four-factor analysis concluded the No. 3 Sinter Plant Sinter Strands have no reasonable set of SO_2 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.

3.2.7 Visibility Benefits

Since the four-factor analysis concluded the No. 3 Sinter Plant Sinter Strands have no reasonable set of SO_2 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 SO_2 emission control measures. However, as described in Section 6, additional SO_2 emission reductions are not appropriate and are unnecessary for Gary Works 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 and Seney), or trending towards (Mingo), the 2028 URP (see Section 6.1),
2. The trajectory analysis demonstrates that Gary Works does not appreciably contribute to visibility impairment to the Class I areas on the most impaired days at the monitors (see Section 6.2), and
3. Any installation of additional emission control measures at Gary Works will not appreciably improve visibility in these Class I areas (see Section 6.2).

3.2.8 Proposed SO_2 Emission Control Measures

The four-factor analysis with visibility benefits evaluation concluded that additional SO_2 emission control measures at the No. 3 Sinter Plant Sinter Strands beyond those described in Section 2.2.1 are not required to make reasonable progress in reducing SO_2 emissions. As such, Gary Works proposes to maintain the existing SO_2 emission control measures.

4 No. 14 Blast Furnace (Stoves and Casthouse)

The following sections describe the analysis for NO_X and SO_2 emission control measures for the No. 14 Blast Furnace Stoves and Casthouse.

4.1 Four-Factor Analysis – NO_X

The following sections describe the four-factor analysis with visibility benefits evaluation for determining the reasonable set of NO_X emission control measures (Section 4.1.1), the evaluation factors (Sections 4.1.3 through 4.1.7), and the proposed emission control measures (Section 4.1.8) for the No. 14 Blast Furnace Stoves and Casthouse.

4.1.1 NO_X Emission Control Measures

4.1.1.1 No. 14 Blast Furnace Stoves

As described in Section 2.2.2, the No. 14 Blast Furnace Stoves already utilize low-NO_X fuel combustion (blast furnace gas) as a NO_X emission control measure. Table 4-1 presents NO_X emission control measures for blast furnace stoves at similar sources, as represented in the RBLC (Appendix A) and their respective air permits (Appendix B).

Table 4-1 Blast Furnace Stoves NO_X Emission Control Measures at Similar Sources

Facility	Emission Unit Description	Allowed Fuels	NO_X Emission Control Measure(s)
ArcelorMittal Indiana Harbor East	No. 7 Blast Furnace Stoves	Pulverized Coal Natural Gas Blast Furnace Gas	None
ArcelorMittal Indiana Harbor West	No. 3 Blast Furnace Stoves No. 4 Blast Furnace Stoves	Not listed	None
ArcelorMittal Burns Harbor	C Blast Furnace D Blast Furnace	Not listed	None
AK Steel Dearborn	EUBFURNACE, group of four stoves EUCFURNACE, group of four stoves	Natural gas Blast furnace gas	LNB
AK Steel Middletown	No. 3 Blast Furnace	Not listed	None
ArcelorMittal Cleveland	Blast Furnace C5 Blast Furnace C6	Not listed	None
U. S. Steel Edgar Thompson	Blast Furnace No. 1 Stoves Blast Furnace No. 3 Stoves	Blast furnace gas Coke oven gas Natural gas	None
Nucor St. James[(1)] (2010 Nucor BACT)	Blast Furnace 1 Blast Furnace 2	Natural gas Blast furnace gas	Low-NO_X fuel combustion[(2)]

(1) The emission units at Nucor St. James have not been constructed.
(2) Nucor St. James identified BACT as low-NO_X fuel combustion through firing blast furnace gas and thus it is explicitly referenced in their permit. However, their operations are not materially different from others in the industry; it is standard operating practice to fire low-NO_X fuel (blast furnace gas) in blast furnace stoves.

The AK Dearborn B and C Furnaces have LNB installed as part of a 2014 Prevention of Significant Deterioration (PSD) Permit. Although LNB are technically feasible to install on blast furnace stoves, it is not clear whether 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" (EPA's Alternative Control Techniques Document)[16]:

> "[…] *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 NOx reduction is considered to be small.*"

It is important to note that Gary Works historically represented the actual NO_X emissions generated from the supplement natural gas combustion at the Blast Furnace Stoves based on a conservatively high AP-42

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[16] EPA, "Alternative Control Techniques Document – NO_X Emissions from Iron and Steel Mills" (EPA-453/R-94-065), 1994, Page 5-22

uncontrolled pre-New Source Performance Standard (NSPS) natural gas boiler emission factor (280 lb/MMscf or 0.275 lb/MMBtu).[17] Since the natural gas is fired as a supplement to the blast furnace gas to meet operating temperatures, the associated AP-42 natural gas emission factor value over-represents thermal NO_X formation because the flame temperatures are less than what would be achieved when firing natural gas exclusively (i.e., basis for the AP-42 emission factor). In Table 4-4 of EPA's Alternative Control Techniques Document, EPA represented the average uncontrolled blast furnace NO_X emission factor as 0.021 lb/MMBtu with a range from 0.002 lb/MMBtu to 0.057 lb/MMBtu. The associated NO_X emission performance is consistent with the range that would be expected from LNB and corroborates EPA's conclusion that 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 the operation of the hot blast stoves. Thus, low NO_X burners are not a feasible control technology for the hot blast stoves.*"[18]

Since LNB represent a negligible or potentially small emission reduction potential, compared to the current NO_X emission control measures, and have the potential operational challenges, LNB are not considered as part of the reasonable set of NO_X emission control measures for the No. 14 Blast Furnace Stoves and are not evaluated further in this analysis.

The No. 14 Blast Furnace 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). Furthermore, the existing NO_X emission control measures are equivalent to those determined to be BACT in the 2010 Nucor BACT evaluation and determination; and, therefore, are considered effective emission controls.

4.1.1.2 No. 14 Blast Furnace Casthouse

Table 4-2 presents NO_X emission control measures for blast furnace casthouses at similar sources, as represented in the RBLC (Appendix A) and their respective air permits (Appendix B).

[17] AP-42 Section 1.4 "Natural Gas Combustion" Table 1.4-1, U. S. Environmental Protection Agency, 1998.

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

Table 4-2 Blast Furnace Casthouse NO_X Emission Control Measures at Similar Sources

Facility	Emission Unit Description	NO_X Emission Control Measure(s)
ArcelorMittal Indiana Harbor East	No. 7 Blast Furnace Casthouse	None
ArcelorMittal Indiana Harbor West	No. 3 Blast Furnace Casthouse	None
	No. 4 Blast Furnace Casthouse	
ArcelorMittal Burns Harbor	C Blast Furnace East and West Casthouses	None
	D Blast Furnace East and West Casthouses	
AK Steel Dearborn	EUBFURNACE Casthouses	None
	EUCFURNACE Casthouses	
AK Steel Middletown	No. 3 Blast Furnace Casthouse	None
ArcelorMittal Cleveland	Blast Furnace C5 Casthouse	None
	Blast Furnace C6 Casthouse	
U. S. Steel Edgar Thompson	Blast Furnace No. 1 Casthouse	None
	Blast Furnace No. 3 Casthouse	

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. However, the 2010 Nucor BACT stated that there are no feasible SO_2 emission control measures because of the corresponding low SO_2 concentration (~4 ppm SO_2) and high exhaust flow rate. Gary Works' NO_X emissions estimates are significantly less than the SO_2 emissions estimates (28.98 tpy NO_X vs. 579.64 tpy SO_2 in 2019); therefore, the corresponding NO_X concentrations would be comparatively lower and outside the effective range for any add-on NO_X emission control measures.

There are no additional NO_X emission control measures based on the 2010 Nucor BACT, emission control measures described in the RBLC (Appendix A) and air permits for similar sources (Appendix B). As such, the No. 14 Blast Furnace Casthouse has no reasonable set of NO_X emission control measures beyond what is currently installed and operated for these emission units. Furthermore, the existing NO_X emission control measures are equivalent to those determined to be BACT in the 2010 Nucor BACT and, therefore, are considered effective emission controls.

4.1.2 Baseline Emission Rates

Since the four-factor analysis concluded the No. 14 Blast Furnace Stoves and Casthouse 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 the No. 14 Blast Furnace Stoves and Casthouse 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. Even in the circumstance where there was an emission control measure identified as part of the reasonable set, the associated emission control measure's cost-effectiveness would not be reasonable because the emission reduction technology would not impact visibility at the associated Class I areas (see Section 6).

4.1.4 Factor 2 – Time Necessary for Compliance

Since the four-factor analysis concluded the No. 14 Blast Furnace Stoves and Casthouse 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 the No. 14 Blast Furnace Stoves and Casthouse 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 the No. 14 Blast Furnace Stoves and Casthouse 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 the No. 14 Blast Furnace Stoves and Casthouse have no reasonable set of NO_X emission control measures beyond what is currently installed and operated, it is not appropriate to describe the potential visibility benefits for additional NO_X emission control measures. However, as described in Section 6, additional NO_X emission reductions are not appropriate and are unnecessary for Gary Works 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 and Seney), or trending towards (Mingo), the 2028 URP (see Section 6.1),
2. The trajectory analysis demonstrates that Gary Works does not appreciably contribute to visibility impairment to the Class I areas on the most impaired days at the monitors (see Section 6.2), and
3. Any installation of additional emission control measures at Gary Works will not appreciably improve visibility in these Class I areas (see Section 6.2).
4. The No. 14 Blast Furnace Casthouse's emissions are fugitive in nature and would not impair visibility at the associated Class I areas (greater than 500 km away from Gary Works).

4.1.8 Proposed NO_X Emission Control Measures

The four-factor analysis with visibility benefits evaluation concluded that additional NO_X emission control measures at the No. 14 Blast Furnace Stoves and Casthouse beyond those described in Section 2.2.1 are not required to make reasonable progress in reducing NO_X emissions. As such, Gary Works proposes to maintain the existing NO_X emission control measures.

4.2 Four-Factor Analysis – SO_2

The following sections describe the four-factor analysis with visibility benefits evaluation for determining the reasonable set of SO_2 emission control measures (Section 4.2.1), the evaluation factors (Sections 4.2.3 through 4.2.7), and the proposed emission control measures (Section 4.2.8) for the No. 14 Blast Furnace Stoves and Casthouse.

4.2.1 SO_2 Emission Control Measures

4.2.1.1 No. 14 Blast Furnace Stoves

As described in Section 2.2.2, the No. 14 Blast Furnace Stoves routinely fires low-sulfur fuels (blast furnace gas and pipeline-grade natural gas) as an existing SO_2 emission control measure. Table 4-3 presents SO_2 emission control measures for blast furnace stoves at similar sources, as represented in the RBLC (Appendix A) and their respective air permits (Appendix B).

Table 4-3 Blast Furnace Stoves SO_2 Emission Control Measures at Similar Sources

Facility	Emission Unit Description	Allowed Fuels	SO_2 Emission Control Measure(s)
ArcelorMittal Indiana Harbor East	No. 7 Blast Furnace Stoves	Natural Gas Blast Furnace Gas	None
ArcelorMittal Indiana Harbor West	No. 3 Blast Furnace Stoves No. 4 Blast Furnace Stoves	Natural gas Blast furnace gas	None
ArcelorMittal Burns Harbor	C Blast Furnace D Blast Furnace	Blast furnace gas Coke oven gas Natural gas	None
AK Steel Dearborn(1)	EUBFURNACE, group of four stoves EUCFURNACE, group of four stoves	Natural gas Blast furnace gas	None
AK Steel Middletown	No. 3 Blast Furnace	Not listed	None
ArcelorMittal Cleveland	Blast Furnace C5 Blast Furnace C6	Natural gas Blast furnace gas	None
U. S. Steel Edgar Thompson	Blast Furnace No. 1 Stoves Blast Furnace No. 3 Stoves	Blast furnace gas Coke oven gas Natural gas	None
Nucor St. James(2) (2010 Nucor BACT)	Blast Furnace 1 Blast Furnace 2	Natural gas Blast furnace gas	Low sulfur fuels

(1) AK Steel Dearborn (RBLCID = MI-0413) underwent SO_2 BACT in 2014 and concluded that BACT did not require additional SO_2 emission control measures.
(2) The emission units at Nucor St. James have not been constructed.

The 2010 Nucor BACT determined that other than the low-sulfur fuels (blast furnace gas and natural gas), no additional add-on SO_2 emission control measures are technically feasible.

There are no additional SO_2 emission control measures based on the 2010 Nucor BACT, emission control measures described in the RBLC (Appendix A) and air permits for similar sources (Appendix B). As such, the No. 14 Blast Furnace Stoves have no reasonable set of SO_2 emission control measures. Furthermore, the existing SO_2 emission control measures are equivalent to those determined to be BACT in the 2010 Nucor BACT and, therefore, are considered effective emission controls.

4.2.1.2 No. 14 Blast Furnace Casthouse

As described in Section 2.2.2, there are no existing SO_2 emission control measures associated with the No. 14 Blast Furnace Casthouse. Table 4-4 presents SO_2 emission control measures for blast furnace casthouses at similar sources, as represented in the RBLC (Appendix A) and their respective air permits (Appendix B).

Table 4-4 Blast Furnace Casthouse SO_2 Emission Control Measures at Similar Sources

Facility	Emission Unit Description	SO_2 Emission Control Measure(s)
ArcelorMittal Indiana Harbor East	No. 7 Blast Furnace Casthouse	None
ArcelorMittal Indiana Harbor West	No. 3 Blast Furnace Casthouse	None
	No. 4 Blast Furnace Casthouse	
ArcelorMittal Burns Harbor	C Blast Furnace East and West Casthouses	None
	D Blast Furnace East and West Casthouses	
AK Steel Dearborn	EUBFURNACE Casthouses	None
	EUCFURNACE Casthouses	
AK Steel Middletown	No. 3 Blast Furnace Casthouse	None
ArcelorMittal Cleveland	Blast Furnace C5 Casthouse	None
	Blast Furnace C6 Casthouse	
U. S. Steel Edgar Thompson	Blast Furnace No. 1 Casthouse	None
	Blast Furnace No. 3 Casthouse	
Nucor St. James(1) (2010 Nucor BACT)	Casthouse No. 1	None
	Casthouse No. 2	

(1) The emission units at Nucor St. James have not been constructed.

There are no additional SO_2 emission control measures based on the 2010 Nucor BACT, emission control measures described in the RBLC (Appendix A) and air permits for similar sources (Appendix B). As such, the No. 14 Blast Furnace Casthouse has no reasonable set of SO_2 emission control measures beyond what is currently installed and operated for these emission units. Furthermore, the existing SO_2 emission control measures are equivalent to those determined to be BACT in the 2010 Nucor BACT and, therefore, are considered effective emission controls.

4.2.2 Baseline Emission Rates

Since the four-factor analysis concluded the No. 14 Blast Furnace Stoves and Casthouse have no reasonable set of SO_2 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.

4.2.3 Factor 1 – Cost of Compliance

Since the four-factor analysis concluded the No. 14 Blast Furnace Stoves and Casthouse have no reasonable set of SO_2 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 SO_2 emission control measures. Even in the circumstance where there was an emission control measure identified as part of the reasonable set, the associated emission control measure's cost-effectiveness would not be reasonable because the emission reduction technology would not impact visibility at the associated Class I areas (see Section 6).

4.2.4 Factor 2 – Time Necessary for Compliance

Since the four-factor analysis concluded the No. 14 Blast Furnace Stoves and Casthouse have no reasonable set of SO_2 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 SO_2 emission control measures.

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

Since the four-factor analysis concluded the No. 14 Blast Furnace Stoves and Casthouse have no reasonable set of SO_2 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 SO_2 emission control measures.

4.2.6 Factor 4 – Remaining Useful Life of the Source

Since the four-factor analysis concluded the No. 14 Blast Furnace Stoves and Casthouse have no reasonable set of SO_2 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.

4.2.7 Visibility Benefits

Since the four-factor analysis concluded the No. 14 Blast Furnace Stoves and Casthouse have no reasonable set of SO_2 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 SO_2 emission control measures. However, as described in Section 6, additional SO_2 emission reductions are not appropriate and are unnecessary for Gary Works 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 and Seney), or trending towards (Mingo), the 2028 URP (see Section 6.1),
2. The trajectory analysis demonstrates that Gary Works does not appreciably contribute to visibility impairment to the Class I areas on the most impaired days at the monitors (see Section 6.2), and
3. Any installation of additional emission control measures at Gary Works will not appreciably improve visibility in these Class I areas (see Section 6.2).
4. The Casthouse's emissions are fugitive in nature (e.g., low-lying, low-velocity source) and would not impair visibility at the associated Class I areas (greater than 500 km away from Gary Works).

4.2.8 Proposed SO_2 Emission Control Measures

The four-factor analysis with visibility benefits evaluation concluded that additional SO_2 emission control measures at the No. 14 Blast Furnace Stoves and Casthouse beyond those described in Section 2.2.1 are not required to make reasonable progress in reducing SO_2 emissions. As such, Gary Works proposes to maintain the existing SO_2 emission control measures.

5 84” Hot Strip Mill Reheat Furnaces and Waste Heat Boilers

The following sections describe the four-factor analysis with visibility benefits evaluation for NO_X emission control measures (Section 5.1), the 2028 projected baseline NO_X emission rates (Section 5.1.2), the evaluation factors (Sections 5.1.3 through 5.1.7), and the proposed emission control measures (Section 5.1.7) for the 84” Hot Strip Mill Reheat Furnaces and Waste Heat Boilers.

5.1 Four-Factor Analysis - NO_X

5.1.1 NO_X Emission Control Measures

As described in Section 2.2.3, the 84” Hot Strip Mill Reheat Furnaces and Waste Heat Boilers conform to good combustion practices and operate ZoloSCAN on the Reheat Furnaces as existing NO_X emission control measures. Table 5-1 presents NO_X emission control measures for reheat furnaces and waste heat boilers at similar sources, as represented in the RBLC (Appendix A) and their respective air permits (Appendix B).

Table 5-1 Reheat Furnaces and Waste Heat Boilers NO_X Emission Control Measures at Similar Sources

Facility	Emission Unit Description	Allowed Fuels	NO_X Emission Control Measure(s)
ArcelorMittal Indiana Harbor East	No. 4 Walking Beam Furnace	Natural gas	LNB
	No. 5 Walking Beam Furnace	Natural gas	None
	No. 6 Walking Beam Furnace	Natural gas	None
ArcelorMittal Indiana Harbor West	No. 1 Reheat Furnace	Natural gas	None
	No. 2 Reheat Furnace		
	No. 3 Reheat Furnace		
ArcelorMittal Burns Harbor	Reheat Furnace No. 1	Natural gas Coke oven gas Propane	None
	Reheat Furnace No. 2		
	Reheat Furnace No. 3		
	HSM WBF No. 1	Natural gas	LNB
	HSM WBF No. 2		
AK Steel Dearborn	EUREHEATFURN1	Not listed	None
	EUREHEATFURN2		
	EUREHEATFURN3		

Facility	Emission Unit Description	Allowed Fuels	NO_X Emission Control Measure(s)
AK Steel Middletown	No. 1 Slab Reheat Furnace/Waste Heat Boiler	Natural gas Fuel oil Coke oven gas	None
	No. 2 Slab Reheat Furnace/Waste Heat Boiler		
	No. 3 Slab Reheat Furnace/Waste Heat Boiler		
	No. 4 Slab Reheat Furnace/Waste Heat Boiler		
ArcelorMittal Cleveland	80" Hot Strip Mill Reheat Furnaces 1, 2, 3	Natural gas Fuel oil	LNB
	Walking Beam Furnace	Natural gas	None

LNB reduces NO_X emissions by decreasing the burner flame temperature from staging either the combustion air or fuel injection rates into the burner. Gary Works identified LNB to be part of the reasonable set of NO_X emission control measures for the 84" Hot Strip Mill Reheat Furnaces and Waste Heat Boilers based on the emission control measures described in the RBLC (Appendix A) and the air permits for similar sources (Appendix B).

The RBLC search (Appendix A) identified two instances of Selective Catalytic Reduction (SCR)[19] for NO_X emission control; A reheat furnace at Thyssenkrupp Steel and Stainless USA, LLC (RBLC ID: AL-0230) and a combined stack with six waste heat boilers and six rotary hearth furnaces at New Steel International, Inc., Haverhill (RBLC ID: OH-0315). The Thyssenkrupp Steel and Stainless USA, LLC (RBLC ID: AL-0230) RBLC entry included an associated note stating: "This covers NO_X for the nitric & hydrofluoric acid pickling with caustic scrubber & DE-NO_X SCR (LA29)." Therefore, it was assumed that the operations are materially different and are not comparable to Gary Works. The New Steel International, Inc., Haverhill (RBLC ID: OH-0315) facility was never constructed and, as such, SCR has not been installed and successfully operated on a similar source under similar physical and operating conditions. Therefore, SCR is not part of a reasonable set of NO_X emission control measures for the 84" Hot Strip Mill Reheat Furnaces and Waste Heat Boilers.

LNB for the 84" Hot Strip Mill Reheat Furnaces and Waste Heat Boilers is evaluated as a NO_X emission control measure in Sections 5.1.3 through 5.1.6.

5.1.2 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

[19] SCR reduces NO_X emissions with ammonia or urea injection in the presence of a catalyst.

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, Gary Works considered the representative historical period to be 2016-2019 and conservatively selected the maximum annual emissions within the associated four-year period to represent projected 2028 baseline emissions. The estimated 2028 baseline NO_X emissions are shown in Table 5-2.

Table 5-2 Estimated 2028 Baseline NO_X Emissions for the Identified Emission Units

Unit	2028 Projected Baseline Natural Gas Throughput Assumption (MMscf/year)	Natural Gas NO_X Emission Factor[1] (lb/MMBtu)	Estimated 2028 NO_X Emissions (tons/year)
Reheat Furnace No. 1	9,960	275	1,293
Reheat Furnace No. 2			
Reheat Furnace No. 3			
Reheat Furnace No. 4			
Waste Heat Boiler No. 1	651	275	89
Waste Heat Boiler No. 2	623	275	86

(1) AP-42 Section 1.4; Table 1.4-1; July 1998

5.1.3 Factor 1 – Cost of Compliance

Gary Works completed cost estimates for LNB installation on the 84" Hot Strip Mill Reheat Furnaces and Waste Heat Boilers. Due to the limited time available in responding to IDEM's request, a source-specific technical feasibility study and preliminary engineering design were not conducted. The cost of compliance analysis is based on information provided by a vendor regarding burner performance and equipment costs. The installation costs were estimated by Gary Works' engineering staff and are based on experience with projects of similar scope. The capital cost estimates are considered by Gary Works' engineering staff, based on their considerable experience with projects at Gary Works and in the industry, to be conservatively low. Cost summary spreadsheets for LNB installation on the 84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4, Waste Heat Boiler No. 1, and Waste Heat Boiler No. 2 are provided in Appendix C.1, C.2, and C.3, respectively.

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 Manual[20], 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 5-3.

Table 5-3 LNB Control Cost Summary, per Unit Basis

Emission Unit	Total Annualized Costs ($/yr)	Annual Emissions Reduction (tpy)	Pollution Control Cost Effectiveness ($/ton)
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4	$2,978,000	211	$14,100
Waste Heat Boiler No. 1	$355,000	58	$6,100
Waste Heat Boiler No. 2	$355,000	56	$6,300

Based on the cost effectiveness values, LNB installation on the 84" Hot Strip Mill Reheat Furnaces and Waste Heat Boilers are not cost-effective. Independent of the cost-effectiveness evaluation, installation of LNBs on the associated units is not justifiable because the emission control measures would not appreciably improve visibility at the associated Class I areas.

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[20] US EPA, "EPA Air Pollution Control Cost Manual, Sixth Edition," January 2002, EPA/452/B-02-001. The EPA has updated certain sections and chapters of the manual since January 2002. These individual sections and chapters may be accessed at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution as of the date of this report., page 2-26

Sections 5.1.4 through 5.1.6 provide a summary of the remaining three factors evaluated for the NO_X emission control measures, understanding that these projects represent substantial capital investments that are not justified on a cost per ton or absolute cost basis.

5.1.4 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 issue Gary Works a significant source modification permit, then time for Gary Works to engineer, fund, install, commission, and test the project necessary to meet the SIP limit.

The technologies would require significant resources and time of at least two to three 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.

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

LNB installation on the 84" Hot Strip Mill Reheat Furnaces and Waste Heat Boilers will result in a small decrease in thermal efficiency due to lower flame temperatures. However, the energy and non-air quality environmental impacts associated with the implementation of LNB are negligible for this analysis.

5.1.6 Factor 4 – Remaining Useful Life of the Source

Because Gary Works 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.

5.1.7 Visibility Benefits

LNB installation on the 84" Hot Strip Mill Reheat Furnaces and Waste Heat Boilers is not appropriate and 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 and Seney), or trending towards (Mingo), the 2028 URP (see Section 6.1),
2. The trajectory analysis demonstrates that Gary Works does not appreciably contribute to visibility impairment to the Class I areas on the most impaired days at the monitors (see Section 6.2), and
3. LNB installation on the 84" Hot Strip Mill Reheat Furnaces and Waste Heat Boilers do not justify the associated cost, as described in Section 5.1.3, because the emission control measure will not appreciably improve visibility in these Class I areas.

5.1.8 Proposed NO_X Emission Control Measures

Based on the analysis conducted in Sections 5.1.3 through 5.1.7, Gary Works has determined that installation of additional NO_X emissions measures at the 84" Hot Strip Mill Reheat Furnaces and Waste Heat Boilers beyond those described in Section 2.2.3 are not required to make reasonable progress in reducing NO_X emissions. As such, Gary Works proposes to maintain the existing NO_X emission control measures.

6 Visibility Impacts Review

Section 6.1 describes the current visibility conditions compared to the 2028 URP and whether emission reductions are necessary to have the 2028 visibility conditions below the 2028 URP. Section 6.2 presents a more complex surrogate analysis for visibility impacts which considers the air trajectories prior to the most impaired visibility days rather than only considering emission rates (Q) and distances (d). The analysis provides the frequency when emissions from Gary Works may have been a contributor to the haze on the selected most impaired days.

6.1 Analysis of Ambient Data

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."[21] The SIP "must consider the uniform rate of improvement in visibility and the emission-reduction measures needed to achieve it for the period covered by the implementation plan."[22]

An analysis of current visibility conditions was completed at the three Class I areas closest to Gary Work's facility (Mammoth Cave, Mingo, and Seney) to determine the current status compared to the natural visibility goal, the 2028 URP, and to the possible reasonable progress goals for the SIP for the second implementation period, which ends in 2028.

Visibility monitoring data was obtained from the IMPROVE monitors at Mammoth Cave (MACA1), Mingo (MING1), and Seney (SENE1).[23] The data was compared to the RHR visibility metric, which is based on the rolling 5-year average of the 20% most anthropogenically impaired days and the 20% clearest days, with visibility being measured in deciviews (dv).

Figure 6-1 through Figure 6-3 show the rolling 5-year average visibility impairment versus the 2028 URP glidepath[24] at Mammoth Cave (MACA1), Mingo (MING1), and Seney (SENE1), respectively. This data illustrates that regional haze impairment at these three Class I areas has been declining (i.e., visibility has been improving) since 2007 for both Seney and Mingo, and 2008 for Mammoth Cave. The trends in visibility impairment fell below the expected 2028 URP goal in 2017 for Seney and Mammoth Cave, and was 0.6 dv from the 2028 goal for Mingo in 2018. All of the data demonstrates that visibility continues to improve in each of these Class I areas.

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[21] 40 CFR 51.308(f)(1)

[22] 40 CFR 51.308(d)(1)

[23] http://vista.cira.colostate.edu/Improve/improve-data/

[24] https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibilityprogress

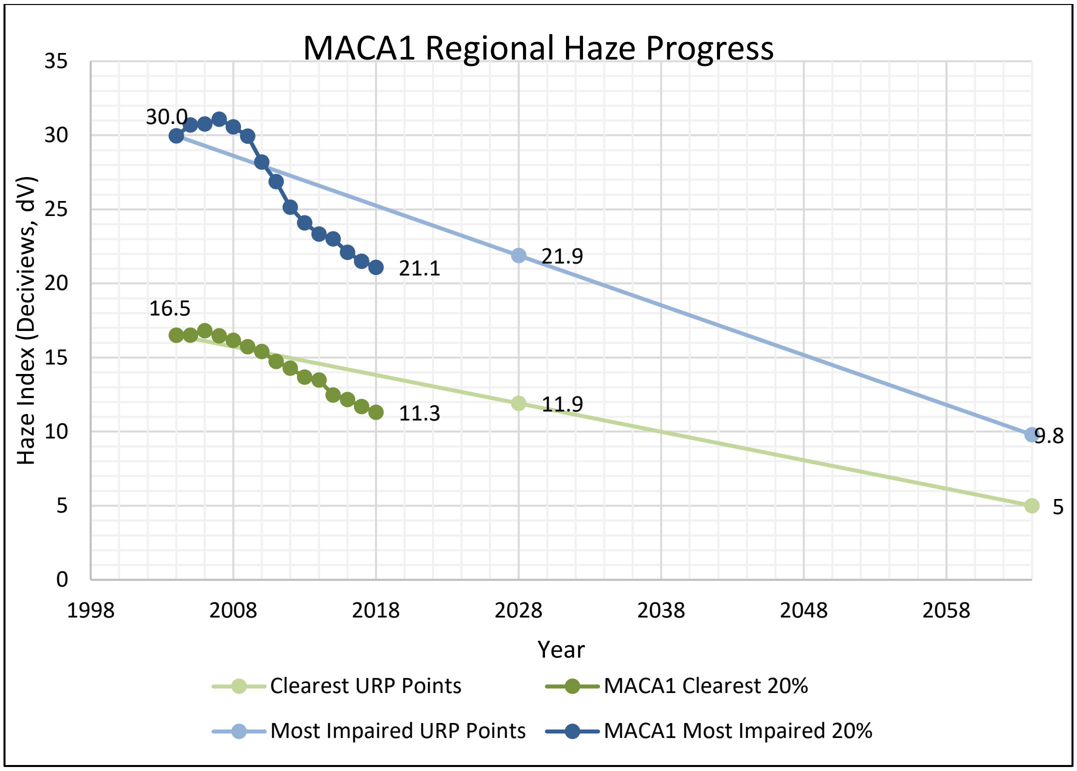

Figure 6-1 Visibility Trend versus 2028 URP – Mammoth Cave National Park (MACA1)

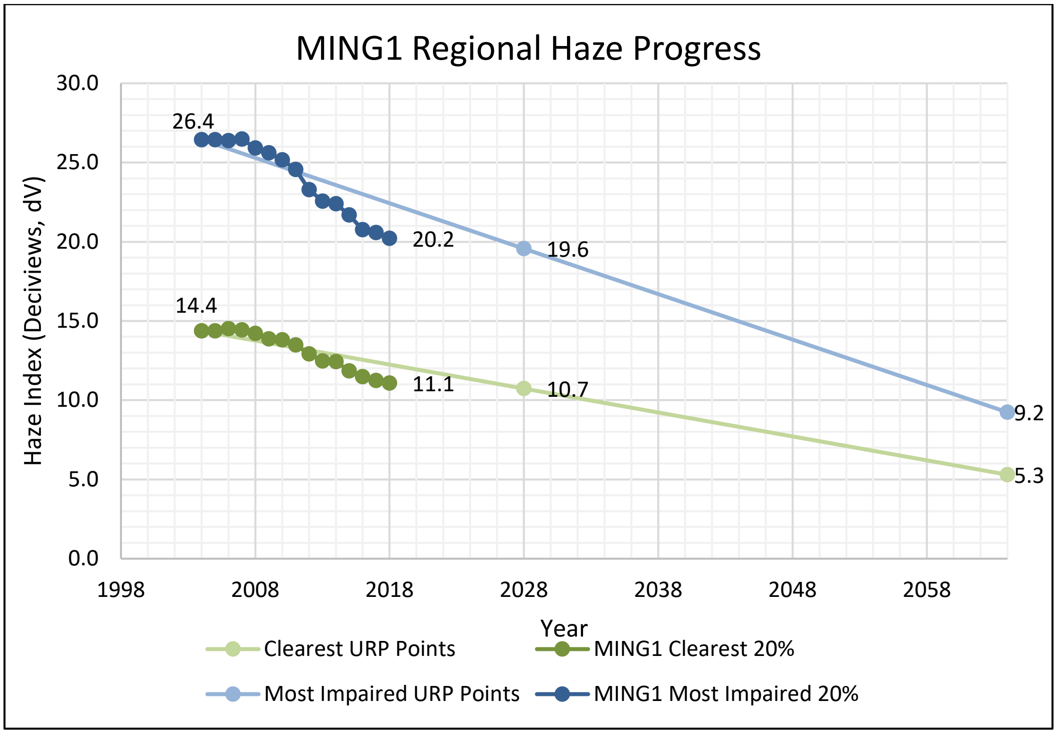

Figure 6-2 Visibility Trend versus 2028 URP – Mingo National Wildlife Refuge (MING1)

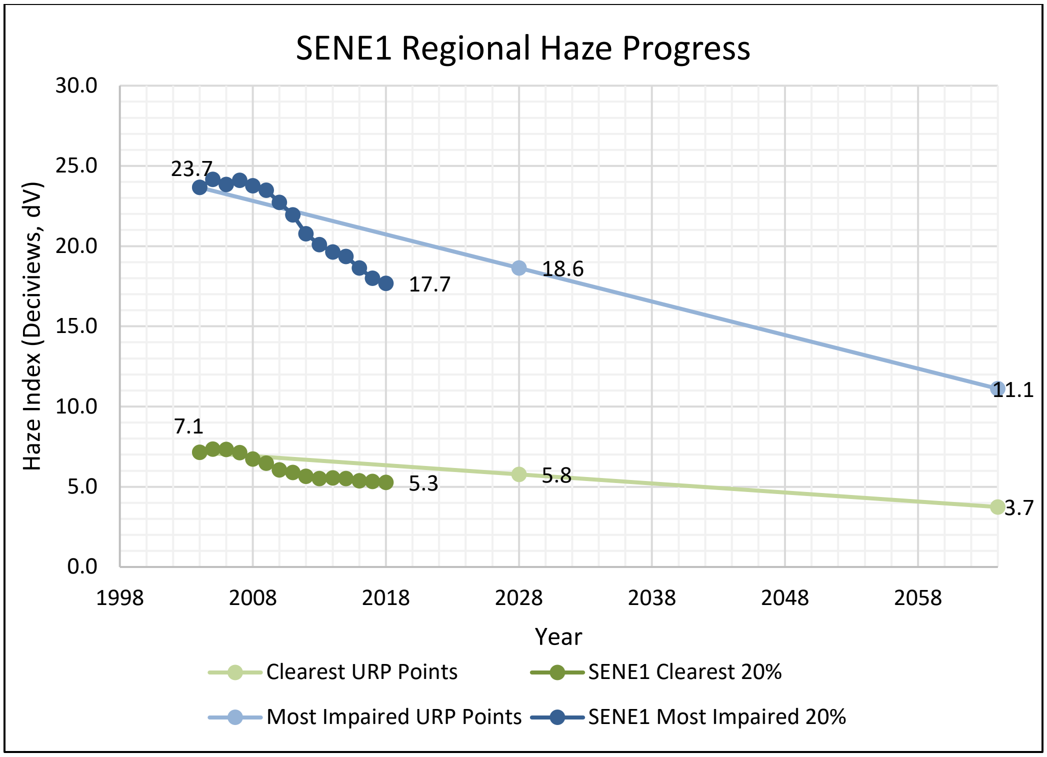

Figure 6-3 Visibility Trend versus 2028 URP – Seney National Wildlife Refuge (SENE1)

The downward visibility trend for each of the Class I monitors described above can be attributed to the reductions across various regional sources. These reductions are a result of a number of different actions taken to reduce emissions from several sources, including:

- Installation of BART during the first RHR implementation period
- Emission reductions from a variety of industries due to updated rules and regulations
- Transition of power generation systems from coal to natural gas and renewables (wind and solar)
- NO_X and SO_2 emission reductions from mobile sources due to numerous federal regulatory programs (e.g., increased fuel economy and low sulfur fuels standards)

The IMPROVE monitoring network data demonstrates sustained progress towards visibility goals and the 5-year average visibility impairment on the most impaired days is already below the 2028 URP at two of the Class I areas which were considered (Mammoth Cave and Seney). In addition, the 5-year visibility impairment at the third Class I area (Mingo) is only slightly above the 2028 URP (20.2 dV observed versus 19.6 dV for the 2028 URP) and has been trending downward since 2007. Furthermore, the 2019 RH SIP Guidance states that "visibility impacts and/or potential benefits may be considered in the source selection step in order to prioritize the examination of certain sources for further analysis of emission control measures."[25] Since the 5-year average visibility impairment on the most impaired days is already below (Mammoth Cave and Seney), or trending towards (Mingo), the 2028 URP, it is not necessary for Gary Works to install additional emission control measures to make reasonable progress at these Class I areas.

6.2 Visibility Impacts

A reverse particle trajectory analysis was completed from the three Class I areas closest to Gary Works (Mammoth Cave, Mingo, and Seney) to determine visibility impacts from Gary Works. These analyses were used to determine how emissions from Gary Works could impact visibility in Class I areas on the most impaired days. These analyses could also be used to determine if emission reductions at Gary Works 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. A reverse trajectory analysis was performed beginning at each Class I area for the calculated most impaired days during 2017-2018. The impairment metric (dv) from the IMPROVE Aerosol RHR III dataset[26] was used to calculate the 20% most impaired days for 2017 and 2018. The NOAA Hysplit model[27] 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.[28] The trajectories that cross near Gary Works are shown in Figure 6-4 and all of the most impaired trajectories in 2017 and 2018 for each Class I area is shown in Figure 6-5 through Figure 6-7.

The analysis considered the 20% most impaired trajectories for each Class 1 area based on 2017 and 2018 IMPROVE data. As shown in Figure 6-4, just 2.5% of the most impaired trajectories cross near Gary Works out of a total of 137 most impaired days. In addition, Figure 6-5 through Figure 6-7 illustrate that the majority of the most impaired trajectories are not traveling from the general direction of Gary Works. Furthermore, most of the 48-hour reverse trajectories end before reaching the Gary Works facility location, indicating that the nearest Class I areas are at a distance far enough away from the facility and

[25] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, Page 34.

[26] 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

[27] 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

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

therefore visibility impairment from the Gary Works facility is unlikely. This information generally demonstrates sources from other regions, and not Gary Works, are contributing to the visibility on the most impaired days at the monitors. For example, the emissions are likely coming from other metropolitan areas such as Louisville, St. Louis, Indianapolis, Columbus, Cincinnati, and Nashville. As such, the installation of additional emission control measures at Gary Works would not improve visibility in these Class I areas.

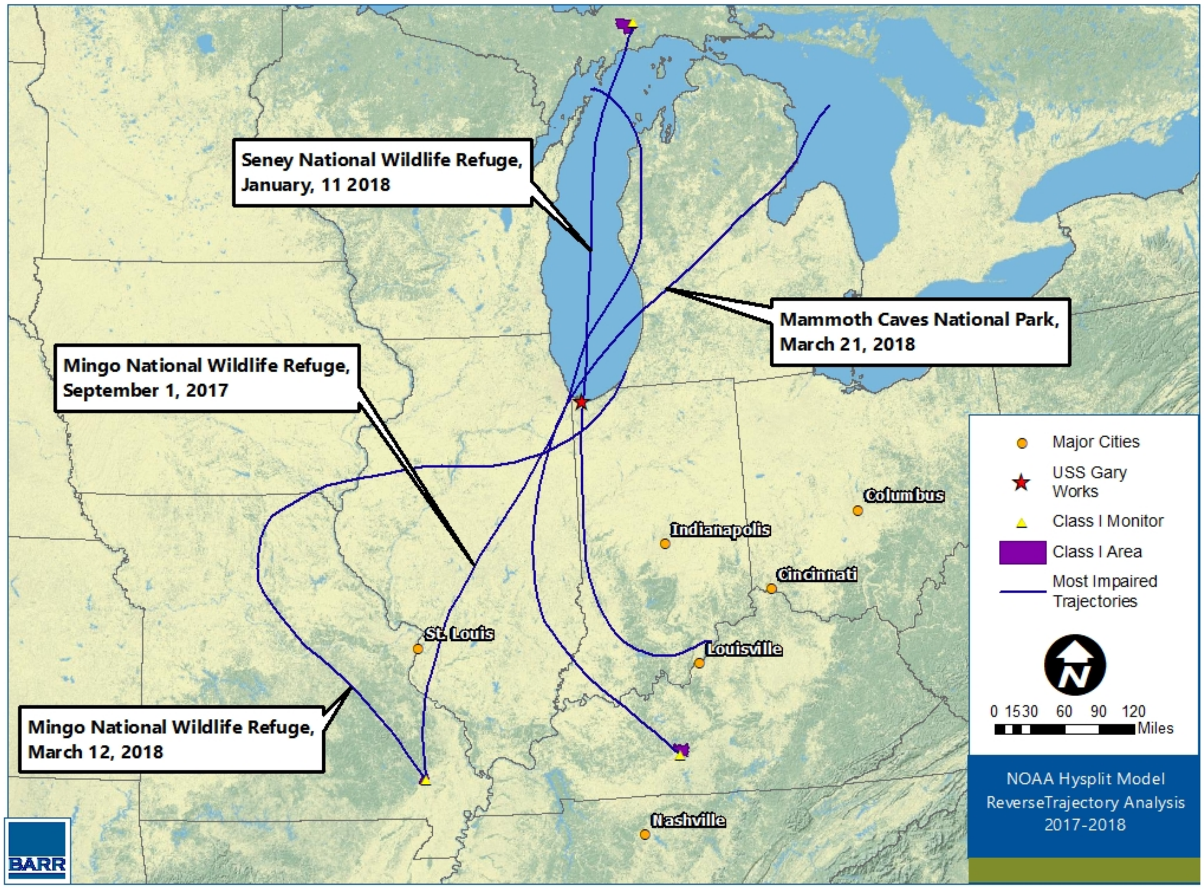

Figure 6-4 Mammoth Cave, Mingo, and Seney: The Most Impaired Trajectories that Cross Near Gary Works from for 2017-2018 (4 out of 150)

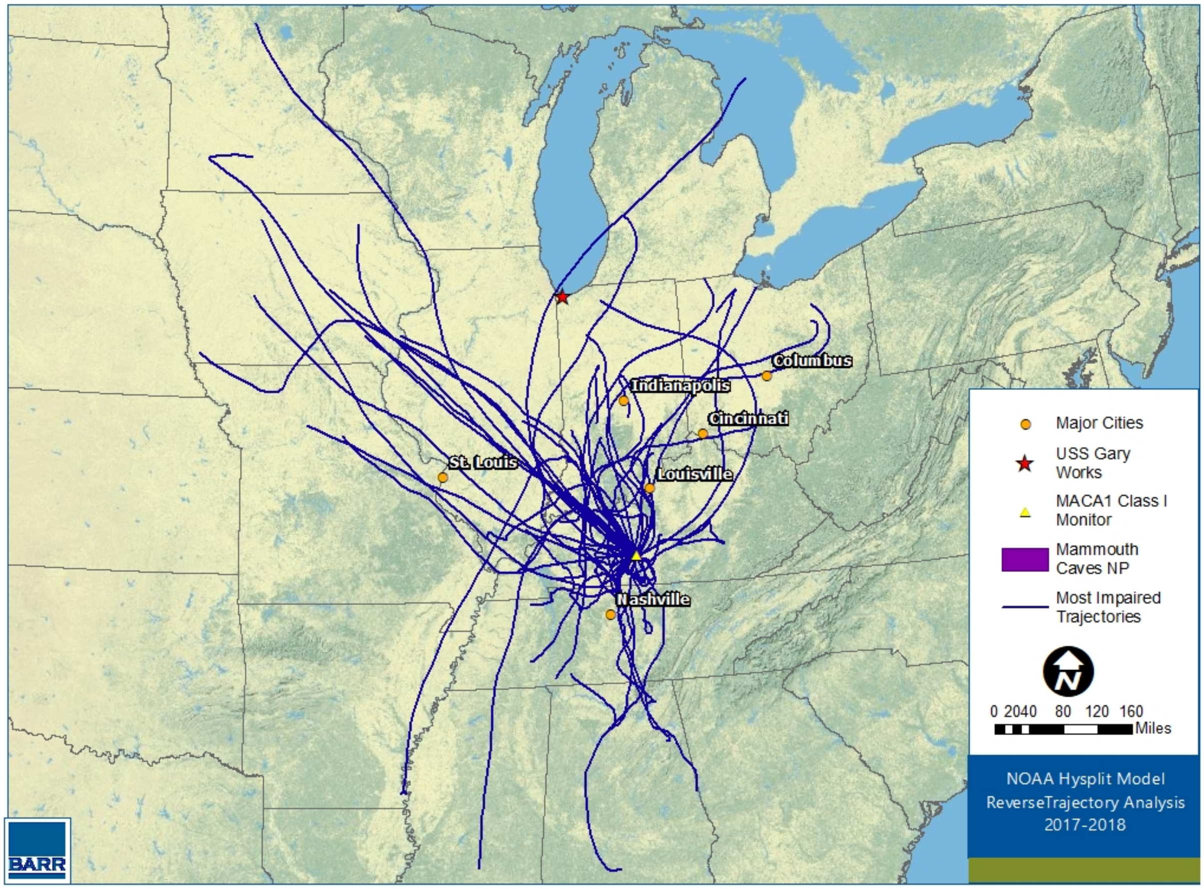

Figure 6-5 **Mammoth Cave National Park: Most Impaired Trajectories for 2017-2018 from Reverse Trajectory Analysis (1 out of 50)**

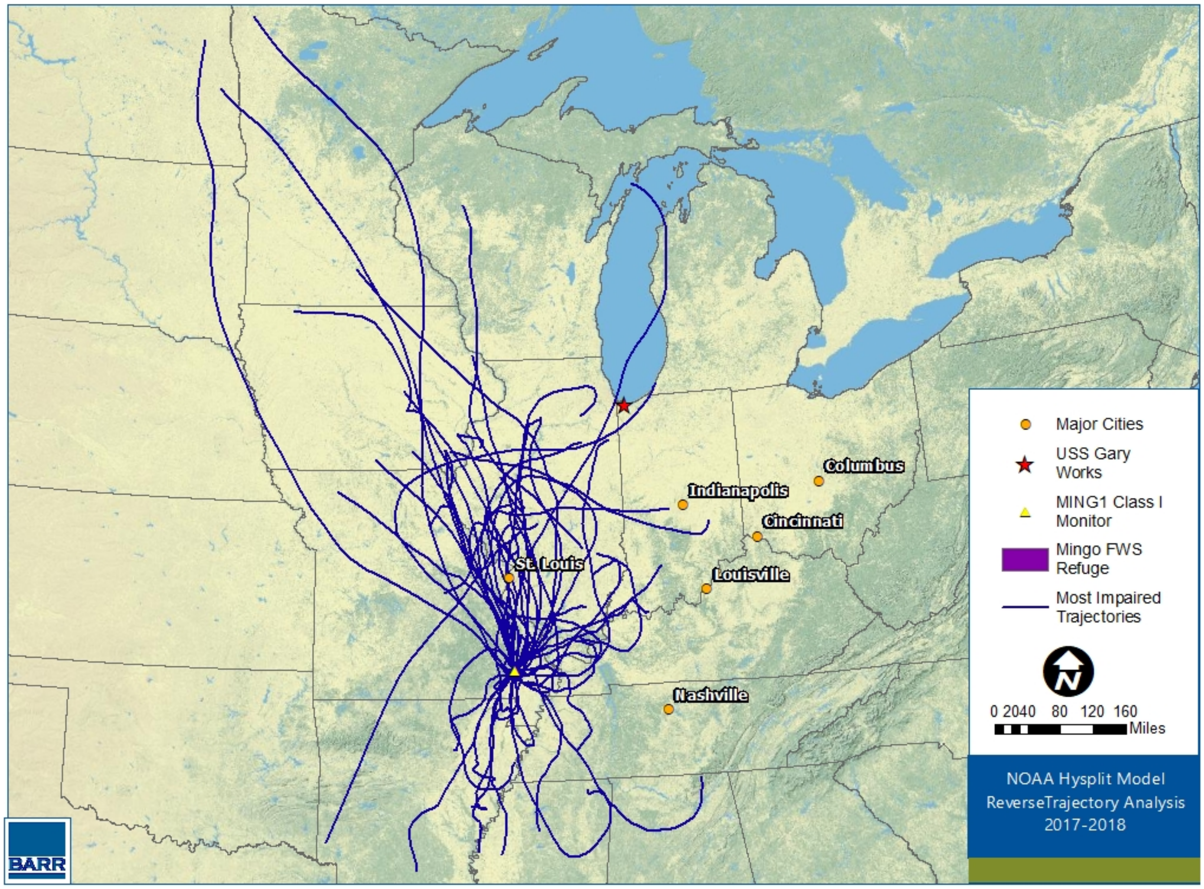

Figure 6-6 Mingo National Wildlife Refuge: Most Impaired Trajectories for 2017-2018 from Reverse Trajectory Analysis (2 out of 50)

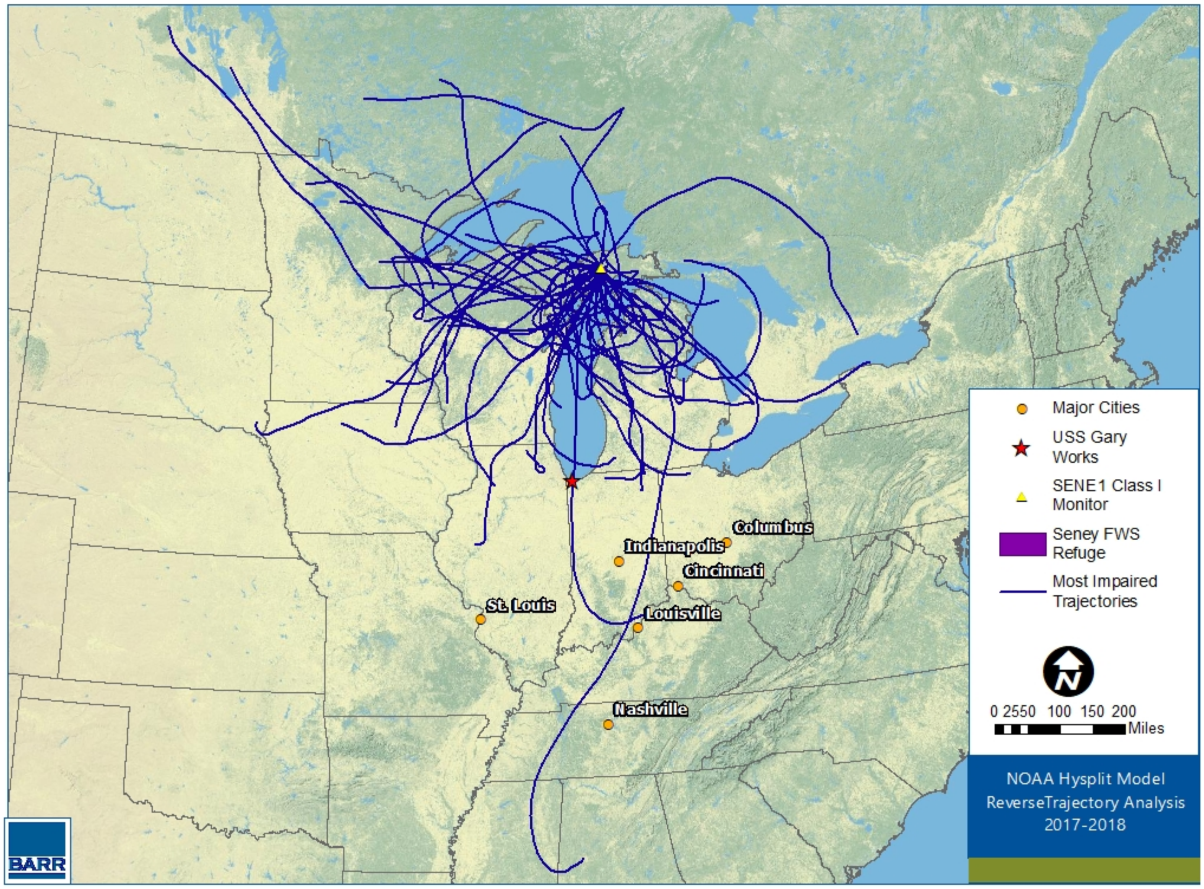

Figure 6-7 Seney National Wildlife Refuge: Most Impaired Trajectories for 2017-2018 from Reverse Trajectory Analysis (1 out of 50)

7 Conclusion

As described in Section 3 and Section 4, the No. 3 Sinter Plant Sinter Strands and No. 14 Blast Furnace (Stoves and Casthouse) four-factor analyses with visibility benefits evaluations concluded that:

- There is no reasonable set of NO_X and SO_2 emission control measures beyond what is currently installed and operated for these emission units (see Sections 3.1.1, 3.2.1, 4.1.1, and 4.2.1).
- The existing emission control measures are equivalent to those determined to be BACT in a recent BACT analysis and, therefore, are considered effective emission controls (see Sections 3.1.1, 3.2.1, 4.1.1, and 4.2.1).
- Additional NO_X and SO_2 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 and Seney), or trending towards (Mingo), the 2028 URP (see Section 6.1),
    - The trajectory analysis demonstrates that Gary Works does not appreciably contribute to visibility impairment to the Class I areas on the most impaired days at the monitors and, therefore, any installation of additional emission control measures at Gary Works will not appreciably improve visibility in these Class I areas (see Section 6.2).
- Therefore, the No. 3 Sinter Plant Sinter Strands and No. 14 Blast Furnace (Stoves and Casthouse) existing NO_X and SO_2 emission performance are sufficient for the IDEM's regional haze reasonable progress goal (see Sections 3.1.8, 3.2.8, 4.1.8, and 4.2.8).

As described in Section 5, the 84" Hot Strip Mill Reheat Furnaces and Waste Heat Boilers NO_X four-factor analysis with visibility benefits evaluation concluded that:

- The reasonable set of NO_X emission control measures beyond what is currently installed and operated for these emission units consists of LNB (see Section 5.1.1).
- LNB installation on the 84" Hot Strip Mill Reheat Furnaces and Waste Heat Boilers are not cost-effective, based on the associated cost-effectiveness values ($ per ton of emissions reduction). Furthermore, the additional capital and operating costs may negatively impact Gary's ability to compete in the economic market (see Section 5.1.3).
- Independent of the cost-effectiveness evaluation, which alone indicates that no additional emission control measures are necessary and appropriate, the additional NO_X emission control measures and their associated NO_X emission reductions are also not necessary and appropriate for Gary Works 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 and Seney), or trending towards (Mingo), the 2028 URP (see Section 6.1),
    - The trajectory analysis demonstrates that Gary Works does not appreciably contribute to visibility impairment to the Class I areas on the most impaired days at the monitors (see Section 6.2), and

    - Thus, the NO_x emission reduction associated with LNB installation on the 84" Hot Strip Mill Reheat Furnaces and Waste Heat Boilers does not justify the associated cost, as described in Section 5.1.3, because the emission control measure will not appreciably improve visibility in these Class I areas (see Section 5.1.7).
- Therefore, the 84" Hot Strip Mill Reheat Furnaces and Waste Heat Boilers existing NO_X emission performance are appropriate and sufficient for the IDEM's regional haze reasonable progress goal (see Section 5.1.8).

In addition to the four statutory factors, this analysis also considered the current visibility and the potential visibility benefits from installing additional emission control measures on the associated sources at the facility. An analysis of current visibility conditions was completed at the three Class I areas closest to Gary Work's facility (~500-570 km away): Mammoth Cave in Kentucky, Seney in northern Michigan and Mingo in Missouri. As shown in Section 6.1, the 5-year average visibility impairment on the most impaired days is already below (Mammoth Cave and Seney), or trending towards (Mingo), the 2028 URP. Thus, it is not necessary for Gary Works to install additional emission control measures to make reasonable progress at these distant Class I areas and, as shown below, any reductions in emissions at Gary Works will not appreciably improve visibility in these Class I areas.

Furthermore, a reverse particle trajectory analysis was completed from these same Class I areas (Mammoth Cave, Mingo, and Seney) to determine how emissions from Gary Works could impact visibility in Class I areas on the 20% most impaired days. As shown in Section 6.1, the majority (97.5%) of the most impaired trajectories are not traveling from the general direction of Gary Works. Furthermore, most of the 48-hour reverse trajectories end before reaching the Gary Works facility location, indicating that the nearest Class I areas are at a distance far enough away from the facility, and therefore Gary Works is not reasonably expected to contribute to visibility impairment of the Class I areas. As such, the installation of additional emission control measures at Gary Works would not improve visibility in these Class I areas on the most impaired days.

Lastly, additional emission control measures could impact the economic viability of the company to continue to operate in competitive economic markets. Gary Works, as well as the entire integrated iron and steel mill industry, is highly sensitive to incremental capital and operating costs due to substantial fluctuation in global economic markets. Considering the current visibility progress and that Gary Works does not appreciably contribute to visibility impairment at the pertinent Class I areas, any additional emission control measures that would be a substantial barrier for the facility to continue to operate would be unreasonable and inappropriate.

Appendix A

RBLC Search Summary for Pertinent Emission Units at Similar Sources

Nitrogen Oxides (NOx)

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	05/24/2010 ACT	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON PER YEAR. THE BASIC RAW MATERIALS FOR THE PIG IRON PRODUCTION PROCESS ARE IRON ORE, IN LUMP OR PELLET FORM; COAL; SINTER; AND FLUX, WHICH MAY BE LIMESTONE, DOLOMITE, OR SLAG. THE FACILITY WILL PROCESS THE COAL INTO METALLURGICAL-GRADE COKE FOR USE IN THE BLAST FURNACES AT DEDICATED COKE OVENS ON THE SITE. THE BLAST FURNACES THEMSELVES ARE CLOSED UNITS WITH VIRTUALLY NO ATMOSPHERIC EMISSIONS. THE COKE OVENS FOLLOW THE HEAT RECOVERY DESIGN. A SINTER PLANT WILL ALSO BE CONSTRUCTED AT THE SITE TO RECYCLE FINE MATERIALS AND DUSTS FOR INCREASED RAW MATERIAL EFFICIENCY. BY RECOVERING HEAT FROM THE COKING PROCESS AND COMBUSTING BLAST FURNACE GAS IN MULTIPLE BOILERS, THE MILL WILL PRODUCE ENOUGH ELECTRICITY TO COMPLETELY PROVIDE FOR FACILITY USAGE AND MAY ALSO PROVIDE SOME ELECTRICAL EXPORT TO THE PUBLIC UTILITY GRID.	SIN-101 - MEROS System Vent Stack	Natural Gas	346	T/H	Nitrogen Oxides (NOx)		188.33	LB/H	3 - HR STACK TEST	BACT-PSD	749.88	T/YR		0.495	LB/TON	FINISHED SINTER PRODUCT

Sulfur Dioxide (SO2)

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	05/24/2010 ACT	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON PER YEAR. THE BASIC RAW MATERIALS FOR THE PIG IRON PRODUCTION PROCESS ARE IRON ORE, IN LUMP OR PELLET FORM; COAL; SINTER; AND FLUX, WHICH MAY BE LIMESTONE, DOLOMITE, OR SLAG. THE FACILITY WILL PROCESS THE COAL INTO METALLURGICAL-GRADE COKE FOR USE IN THE BLAST FURNACES AT DEDICATED COKE OVENS ON THE SITE. THE BLAST FURNACES THEMSELVES ARE CLOSED UNITS WITH VIRTUALLY NO ATMOSPHERIC EMISSIONS. THE COKE OVENS FOLLOW THE HEAT RECOVERY DESIGN. A SINTER PLANT WILL ALSO BE CONSTRUCTED AT THE SITE TO RECYCLE FINE MATERIALS AND DUSTS FOR INCREASED RAW MATERIAL EFFICIENCY. BY RECOVERING HEAT FROM THE COKING PROCESS AND COMBUSTING BLAST FURNACE GAS IN MULTIPLE BOILERS, THE MILL WILL PRODUCE ENOUGH ELECTRICITY TO COMPLETELY PROVIDE FOR FACILITY USAGE AND MAY ALSO PROVIDE SOME ELECTRICAL EXPORT TO THE PUBLIC UTILITY GRID.	SIN-101 - MEROS System Vent Stack	Natural Gas	346	T/H	Sulfur Dioxide (SO2)	Dry scrubbing using a lime spray dryer	121.63	LB/H	3 - HOUR STACK TEST	BACT-PSD	361.14	T/YR		0.437	GRAINS/DSCF	

U. S. Steel Gary Works
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix A: RBLC Search Summary for Pertinent Emission Units at Similar Sources
Blast Furnace

Nitrogen Oxides (NOx)

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON PER YEAR. THE BASIC RAW MATERIALS FOR THE PIG IRON PRODUCTION PROCESS ARE IRON ORE, IN LUMP OR PELLET FORM; COAL; SINTER; AND FLUX, WHICH MAY BE LIMESTONE, DOLOMITE, OR SLAG. THE FACILITY WILL PROCESS THE COAL INTO METALLURGICAL-GRADE COKE FOR USE IN THE BLAST FURNACES AT DEDICATED COKE OVENS ON THE SITE. THE BLAST FURNACES THEMSELVES ARE CLOSED UNITS WITH VIRTUALLY NO ATMOSPHERIC EMISSIONS. THE COKE OVENS FOLLOW THE HEAT RECOVERY DESIGN. A SINTER PLANT WILL ALSO BE CONSTRUCTED AT THE SITE TO RECYCLE FINE MATERIALS AND DUSTS FOR INCREASED RAW MATERIAL EFFICIENCY. BY RECOVERING HEAT FROM THE COKING PROCESS AND COMBUSTING BLAST FURNACE GAS IN MULTIPLE BOILERS, THE MILL WILL PRODUCE ENOUGH ELECTRICITY TO COMPLETELY PROVIDE FOR FACILITY USAGE AND MAY ALSO PROVIDE SOME ELECTRICAL EXPORT TO THE PUBLIC UTILITY GRID.	SLG-104 - Blast Furnace 1 Slag Pit 1		28.66	T/H	Nitrogen Oxides (NOx)		0.71	LB/H		BACT-PSD	0.47	T/YR		0.0248	LB/T OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON PER YEAR. THE BASIC RAW MATERIALS FOR THE PIG IRON PRODUCTION PROCESS ARE IRON ORE, IN LUMP OR PELLET FORM; COAL; SINTER; AND FLUX, WHICH MAY BE LIMESTONE, DOLOMITE, OR SLAG. THE FACILITY WILL PROCESS THE COAL INTO METALLURGICAL-GRADE COKE FOR USE IN THE BLAST FURNACES AT DEDICATED COKE OVENS ON THE SITE. THE BLAST FURNACES THEMSELVES ARE CLOSED UNITS WITH VIRTUALLY NO ATMOSPHERIC EMISSIONS. THE COKE OVENS FOLLOW THE HEAT RECOVERY DESIGN. A SINTER PLANT WILL ALSO BE CONSTRUCTED AT THE SITE TO RECYCLE FINE MATERIALS AND DUSTS FOR INCREASED RAW MATERIAL EFFICIENCY. BY RECOVERING HEAT FROM THE COKING PROCESS AND COMBUSTING BLAST FURNACE GAS IN MULTIPLE BOILERS, THE MILL WILL PRODUCE ENOUGH ELECTRICITY TO COMPLETELY PROVIDE FOR FACILITY USAGE AND MAY ALSO PROVIDE SOME ELECTRICAL EXPORT TO THE PUBLIC UTILITY GRID.	SLG-105 - Blast Furnace 1 Slag Pit 2		28.66	T/H	Nitrogen Oxides (NOx)		0.71	LB/H		BACT-PSD	0.47	T/YR		0.0248	LB/T OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON PER YEAR. THE BASIC RAW MATERIALS FOR THE PIG IRON PRODUCTION PROCESS ARE IRON ORE, IN LUMP OR PELLET FORM; COAL; SINTER; AND FLUX, WHICH MAY BE LIMESTONE, DOLOMITE, OR SLAG. THE FACILITY WILL PROCESS THE COAL INTO METALLURGICAL-GRADE COKE FOR USE IN THE BLAST FURNACES AT DEDICATED COKE OVENS ON THE SITE. THE BLAST FURNACES THEMSELVES ARE CLOSED UNITS WITH VIRTUALLY NO ATMOSPHERIC EMISSIONS. THE COKE OVENS FOLLOW THE HEAT RECOVERY DESIGN. A SINTER PLANT WILL ALSO BE CONSTRUCTED AT THE SITE TO RECYCLE FINE MATERIALS AND DUSTS FOR INCREASED RAW MATERIAL EFFICIENCY. BY RECOVERING HEAT FROM THE COKING PROCESS AND COMBUSTING BLAST FURNACE GAS IN MULTIPLE BOILERS, THE MILL WILL PRODUCE ENOUGH ELECTRICITY TO COMPLETELY PROVIDE FOR FACILITY USAGE AND MAY ALSO PROVIDE SOME ELECTRICAL EXPORT TO THE PUBLIC UTILITY GRID.	SLG-106 - Blast Furnace 1 Slag Pit 3		28.66	T/H	Nitrogen Oxides (NOx)		0.71	LB/H		BACT-PSD	0.47	T/YR		0.0248	LB/T OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON PER YEAR. THE BASIC RAW MATERIALS FOR THE PIG IRON PRODUCTION PROCESS ARE IRON ORE, IN LUMP OR PELLET FORM; COAL; SINTER; AND FLUX, WHICH MAY BE LIMESTONE, DOLOMITE, OR SLAG. THE FACILITY WILL PROCESS THE COAL INTO METALLURGICAL-GRADE COKE FOR USE IN THE BLAST FURNACES AT DEDICATED COKE OVENS ON THE SITE. THE BLAST FURNACES THEMSELVES ARE CLOSED UNITS WITH VIRTUALLY NO ATMOSPHERIC EMISSIONS. THE COKE OVENS FOLLOW THE HEAT RECOVERY DESIGN. A SINTER PLANT WILL ALSO BE CONSTRUCTED AT THE SITE TO RECYCLE FINE MATERIALS AND DUSTS FOR INCREASED RAW MATERIAL EFFICIENCY. BY RECOVERING HEAT FROM THE COKING PROCESS AND COMBUSTING BLAST FURNACE GAS IN MULTIPLE BOILERS, THE MILL WILL PRODUCE ENOUGH ELECTRICITY TO COMPLETELY PROVIDE FOR FACILITY USAGE AND MAY ALSO PROVIDE SOME ELECTRICAL EXPORT TO THE PUBLIC UTILITY GRID.	SLG-204 - Blast Furnace 2 Slag Pit 1		28.66	T/h	Nitrogen Oxides (NOx)		0.71	LB/H		BACT-PSD	0.47	T/YR		0.0248	LB/T OF SLAG	

U. S. Steel Gary Works
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix A: RBLC Search Summary for Pertinent Emission Units at Similar Sources
Blast Furnace

Nitrogen Oxides (NOx)

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON PER YEAR. THE BASIC RAW MATERIALS FOR THE PIG IRON PRODUCTION PROCESS ARE IRON ORE, IN LUMP OR PELLET FORM; COAL; SINTER; AND FLUX, WHICH MAY BE LIMESTONE, DOLOMITE, OR SLAG. THE FACILITY WILL PROCESS THE COAL INTO METALLURGICAL-GRADE COKE FOR USE IN THE BLAST FURNACES AT DEDICATED COKE OVENS ON THE SITE. THE BLAST FURNACES THEMSELVES ARE CLOSED UNITS WITH VIRTUALLY NO ATMOSPHERIC EMISSIONS. THE COKE OVENS FOLLOW THE HEAT RECOVERY DESIGN. A SINTER PLANT WILL ALSO BE CONSTRUCTED AT THE SITE TO RECYCLE FINE MATERIALS AND DUSTS FOR INCREASED RAW MATERIAL EFFICIENCY. BY RECOVERING HEAT FROM THE COKING PROCESS AND COMBUSTING BLAST FURNACE GAS IN MULTIPLE BOILERS, THE MILL WILL PRODUCE ENOUGH ELECTRICITY TO COMPLETELY PROVIDE FOR FACILITY USAGE AND MAY ALSO PROVIDE SOME ELECTRICAL EXPORT TO THE PUBLIC UTILITY GRID.	SLG-205 - Blast Furnace 2 Slag Pit 2		28.66	t/h	Nitrogen Oxides (NOx)		0.71	LB/H		BACT-PSD	0.47	T/YR		0.0248	LB/TON OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON PER YEAR. THE BASIC RAW MATERIALS FOR THE PIG IRON PRODUCTION PROCESS ARE IRON ORE, IN LUMP OR PELLET FORM; COAL; SINTER; AND FLUX, WHICH MAY BE LIMESTONE, DOLOMITE, OR SLAG. THE FACILITY WILL PROCESS THE COAL INTO METALLURGICAL-GRADE COKE FOR USE IN THE BLAST FURNACES AT DEDICATED COKE OVENS ON THE SITE. THE BLAST FURNACES THEMSELVES ARE CLOSED UNITS WITH VIRTUALLY NO ATMOSPHERIC EMISSIONS. THE COKE OVENS FOLLOW THE HEAT RECOVERY DESIGN. A SINTER PLANT WILL ALSO BE CONSTRUCTED AT THE SITE TO RECYCLE FINE MATERIALS AND DUSTS FOR INCREASED RAW MATERIAL EFFICIENCY. BY RECOVERING HEAT FROM THE COKING PROCESS AND COMBUSTING BLAST FURNACE GAS IN MULTIPLE BOILERS, THE MILL WILL PRODUCE ENOUGH ELECTRICITY TO COMPLETELY PROVIDE FOR FACILITY USAGE AND MAY ALSO PROVIDE SOME ELECTRICAL EXPORT TO THE PUBLIC UTILITY GRID.	SLG-206 - Blast Furnace 2 Slag Pit 3		28.66	t/h	Nitrogen Oxides (NOx)		0.71	LB/H		BACT-PSD	0.47	T/YR		0.0248	LB/TON OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	05/24/2010 ACT	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON PER YEAR. THE BASIC RAW MATERIALS FOR THE PIG IRON PRODUCTION PROCESS ARE IRON ORE, IN LUMP OR PELLET FORM; COAL; SINTER; AND FLUX, WHICH MAY BE LIMESTONE, DOLOMITE, OR SLAG. THE FACILITY WILL PROCESS THE COAL INTO METALLURGICAL-GRADE COKE FOR USE IN THE BLAST FURNACES AT DEDICATED COKE OVENS ON THE SITE. THE BLAST FURNACES THEMSELVES ARE CLOSED UNITS WITH VIRTUALLY NO ATMOSPHERIC EMISSIONS. THE COKE OVENS FOLLOW THE HEAT RECOVERY DESIGN. A SINTER PLANT WILL ALSO BE CONSTRUCTED AT THE SITE TO RECYCLE FINE MATERIALS AND DUSTS FOR INCREASED RAW MATERIAL EFFICIENCY. BY RECOVERING HEAT FROM THE COKING PROCESS AND COMBUSTING BLAST FURNACE GAS IN MULTIPLE BOILERS, THE MILL WILL PRODUCE ENOUGH ELECTRICITY TO COMPLETELY PROVIDE FOR FACILITY USAGE AND MAY ALSO PROVIDE SOME ELECTRICAL EXPORT TO THE PUBLIC UTILITY GRID.	STV-101-Blast Furnace 1 Hot Blast Stoves Common Stack	Blast Furnace Gas	627.04	MMBTU/H	Nitrogen Oxides (NOx)	Low-NOx fuel combustion	66.29	LB/H		BACT-PSD	161.23	T/YR		0.06	LB/MMBTU	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	05/24/2010 ACT	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON PER YEAR. THE BASIC RAW MATERIALS FOR THE PIG IRON PRODUCTION PROCESS ARE IRON ORE, IN LUMP OR PELLET FORM; COAL; SINTER; AND FLUX, WHICH MAY BE LIMESTONE, DOLOMITE, OR SLAG. THE FACILITY WILL PROCESS THE COAL INTO METALLURGICAL-GRADE COKE FOR USE IN THE BLAST FURNACES AT DEDICATED COKE OVENS ON THE SITE. THE BLAST FURNACES THEMSELVES ARE CLOSED UNITS WITH VIRTUALLY NO ATMOSPHERIC EMISSIONS. THE COKE OVENS FOLLOW THE HEAT RECOVERY DESIGN. A SINTER PLANT WILL ALSO BE CONSTRUCTED AT THE SITE TO RECYCLE FINE MATERIALS AND DUSTS FOR INCREASED RAW MATERIAL EFFICIENCY. BY RECOVERING HEAT FROM THE COKING PROCESS AND COMBUSTING BLAST FURNACE GAS IN MULTIPLE BOILERS, THE MILL WILL PRODUCE ENOUGH ELECTRICITY TO COMPLETELY PROVIDE FOR FACILITY USAGE AND MAY ALSO PROVIDE SOME ELECTRICAL EXPORT TO THE PUBLIC UTILITY GRID.	STV-201-Blast Furnace 2 Hot Blast Stoves Common Stack	Blast Furnace Gas	627.04	MMBTU/H	Nitrogen Oxides (NOx)	Low-NOx fuel combustion	66.29	LB/H		BACT-PSD	161.23	T/YR		0.06	LB/MMBTU	

U. S. Steel Gary Works
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix A: RBLC Search Summary for Pertinent Emission Units at Similar Sources
Blast Furnace

Sulfur Dioxide (SO2)

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON PER YEAR. THE BASIC RAW MATERIALS FOR THE PIG IRON PRODUCTION PROCESS ARE IRON ORE, IN LUMP OR PELLET FORM; COAL; SINTER; AND FLUX, WHICH MAY BE LIMESTONE, DOLOMITE, OR SLAG. THE FACILITY WILL PROCESS THE COAL INTO METALLURGICAL-GRADE COKE FOR USE IN THE BLAST FURNACES AT DEDICATED COKE OVENS ON THE SITE. THE BLAST FURNACES THEMSELVES ARE CLOSED UNITS WITH VIRTUALLY NO ATMOSPHERIC EMISSIONS. THE COKE OVENS FOLLOW THE HEAT RECOVERY DESIGN. A SINTER PLANT WILL ALSO BE CONSTRUCTED AT THE SITE TO RECYCLE FINE MATERIALS AND DUSTS FOR INCREASED RAW MATERIAL EFFICIENCY. BY RECOVERING HEAT FROM THE COKING PROCESS AND COMBUSTING BLAST FURNACE GAS IN MULTIPLE BOILERS, THE MILL WILL PRODUCE ENOUGH ELECTRICITY TO COMPLETELY PROVIDE FOR FACILITY USAGE AND MAY ALSO PROVIDE SOME ELECTRICAL EXPORT TO THE PUBLIC UTILITY GRID.	SLG-104 - Blast Furnace 1 Slag Pit 1		28.66	T/H	Sulfur Dioxide (SO2)		3.28	LB/H		BACT-PSD	2.16	T/YR		0.115	LB/ OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON PER YEAR. THE BASIC RAW MATERIALS FOR THE PIG IRON PRODUCTION PROCESS ARE IRON ORE, IN LUMP OR PELLET FORM; COAL; SINTER; AND FLUX, WHICH MAY BE LIMESTONE, DOLOMITE, OR SLAG. THE FACILITY WILL PROCESS THE COAL INTO METALLURGICAL-GRADE COKE FOR USE IN THE BLAST FURNACES AT DEDICATED COKE OVENS ON THE SITE. THE BLAST FURNACES THEMSELVES ARE CLOSED UNITS WITH VIRTUALLY NO ATMOSPHERIC EMISSIONS. THE COKE OVENS FOLLOW THE HEAT RECOVERY DESIGN. A SINTER PLANT WILL ALSO BE CONSTRUCTED AT THE SITE TO RECYCLE FINE MATERIALS AND DUSTS FOR INCREASED RAW MATERIAL EFFICIENCY. BY RECOVERING HEAT FROM THE COKING PROCESS AND COMBUSTING BLAST FURNACE GAS IN MULTIPLE BOILERS, THE MILL WILL PRODUCE ENOUGH ELECTRICITY TO COMPLETELY PROVIDE FOR FACILITY USAGE AND MAY ALSO PROVIDE SOME ELECTRICAL EXPORT TO THE PUBLIC UTILITY GRID.	SLG-105 - Blast Furnace 1 Slag Pit 2		28.66	T/H	Sulfur Dioxide (SO2)		3.28	LB/H		BACT-PSD	2.16	T/YR		0.115	LB/T OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON PER YEAR. THE BASIC RAW MATERIALS FOR THE PIG IRON PRODUCTION PROCESS ARE IRON ORE, IN LUMP OR PELLET FORM; COAL; SINTER; AND FLUX, WHICH MAY BE LIMESTONE, DOLOMITE, OR SLAG. THE FACILITY WILL PROCESS THE COAL INTO METALLURGICAL-GRADE COKE FOR USE IN THE BLAST FURNACES AT DEDICATED COKE OVENS ON THE SITE. THE BLAST FURNACES THEMSELVES ARE CLOSED UNITS WITH VIRTUALLY NO ATMOSPHERIC EMISSIONS. THE COKE OVENS FOLLOW THE HEAT RECOVERY DESIGN. A SINTER PLANT WILL ALSO BE CONSTRUCTED AT THE SITE TO RECYCLE FINE MATERIALS AND DUSTS FOR INCREASED RAW MATERIAL EFFICIENCY. BY RECOVERING HEAT FROM THE COKING PROCESS AND COMBUSTING BLAST FURNACE GAS IN MULTIPLE BOILERS, THE MILL WILL PRODUCE ENOUGH ELECTRICITY TO COMPLETELY PROVIDE FOR FACILITY USAGE AND MAY ALSO PROVIDE SOME ELECTRICAL EXPORT TO THE PUBLIC UTILITY GRID.	SLG-106 - Blast Furnace 1 Slag Pit 3		28.66	T/H	Sulfur Dioxide (SO2)		3.28	LB/H		BACT-PSD	2.16	T/YR		0.115	LB/T OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON PER YEAR. THE BASIC RAW MATERIALS FOR THE PIG IRON PRODUCTION PROCESS ARE IRON ORE, IN LUMP OR PELLET FORM; COAL; SINTER; AND FLUX, WHICH MAY BE LIMESTONE, DOLOMITE, OR SLAG. THE FACILITY WILL PROCESS THE COAL INTO METALLURGICAL-GRADE COKE FOR USE IN THE BLAST FURNACES AT DEDICATED COKE OVENS ON THE SITE. THE BLAST FURNACES THEMSELVES ARE CLOSED UNITS WITH VIRTUALLY NO ATMOSPHERIC EMISSIONS. THE COKE OVENS FOLLOW THE HEAT RECOVERY DESIGN. A SINTER PLANT WILL ALSO BE CONSTRUCTED AT THE SITE TO RECYCLE FINE MATERIALS AND DUSTS FOR INCREASED RAW MATERIAL EFFICIENCY. BY RECOVERING HEAT FROM THE COKING PROCESS AND COMBUSTING BLAST FURNACE GAS IN MULTIPLE BOILERS, THE MILL WILL PRODUCE ENOUGH ELECTRICITY TO COMPLETELY PROVIDE FOR FACILITY USAGE AND MAY ALSO PROVIDE SOME ELECTRICAL EXPORT TO THE PUBLIC UTILITY GRID.	SLG-204 - Blast Furnace 2 Slag Pit 1		28.66	T/h	Sulfur Dioxide (SO2)		3.28	LB/H		BACT-PSD	2.16	T/YR		0.115	LB/TON OF SLAG	

U. S. Steel Gary Works
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix A: RBLC Search Summary for Pertinent Emission Units at Similar Sources
Blast Furnace

Sulfur Dioxide (SO2)

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON PER YEAR. THE BASIC RAW MATERIALS FOR THE PIG IRON PRODUCTION PROCESS ARE IRON ORE, IN LUMP OR PELLET FORM; COAL; SINTER; AND FLUX, WHICH MAY BE LIMESTONE, DOLOMITE, OR SLAG. THE FACILITY WILL PROCESS THE COAL INTO METALLURGICAL-GRADE COKE FOR USE IN THE BLAST FURNACES AT DEDICATED COKE OVENS ON THE SITE. THE BLAST FURNACES THEMSELVES ARE CLOSED UNITS WITH VIRTUALLY NO ATMOSPHERIC EMISSIONS. THE COKE OVENS FOLLOW THE HEAT RECOVERY DESIGN. A SINTER PLANT WILL ALSO BE CONSTRUCTED AT THE SITE TO RECYCLE FINE MATERIALS AND DUSTS FOR INCREASED RAW MATERIAL EFFICIENCY. BY RECOVERING HEAT FROM THE COKING PROCESS AND COMBUSTING BLAST FURNACE GAS IN MULTIPLE BOILERS, THE MILL WILL PRODUCE ENOUGH ELECTRICITY TO COMPLETELY PROVIDE FOR FACILITY USAGE AND MAY ALSO PROVIDE SOME ELECTRICAL EXPORT TO THE PUBLIC UTILITY GRID.	SLG-205 - Blast Furnace 2 Slag Pit 2		28.66	t/h	Sulfur Dioxide (SO2)		3.28	LB/H		BACT-PSD	2.16	T/YR		0.115	LB/TON OF SLAG	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	5/24/2010	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON PER YEAR. THE BASIC RAW MATERIALS FOR THE PIG IRON PRODUCTION PROCESS ARE IRON ORE, IN LUMP OR PELLET FORM; COAL; SINTER; AND FLUX, WHICH MAY BE LIMESTONE, DOLOMITE, OR SLAG. THE FACILITY WILL PROCESS THE COAL INTO METALLURGICAL-GRADE COKE FOR USE IN THE BLAST FURNACES AT DEDICATED COKE OVENS ON THE SITE. THE BLAST FURNACES THEMSELVES ARE CLOSED UNITS WITH VIRTUALLY NO ATMOSPHERIC EMISSIONS. THE COKE OVENS FOLLOW THE HEAT RECOVERY DESIGN. A SINTER PLANT WILL ALSO BE CONSTRUCTED AT THE SITE TO RECYCLE FINE MATERIALS AND DUSTS FOR INCREASED RAW MATERIAL EFFICIENCY. BY RECOVERING HEAT FROM THE COKING PROCESS AND COMBUSTING BLAST FURNACE GAS IN MULTIPLE BOILERS, THE MILL WILL PRODUCE ENOUGH ELECTRICITY TO COMPLETELY PROVIDE FOR FACILITY USAGE AND MAY ALSO PROVIDE SOME ELECTRICAL EXPORT TO THE PUBLIC UTILITY GRID.	SLG-206 - Blast Furnace 2 Slag Pit 3		28.66	t/h	Sulfur Dioxide (SO2)		3.28	LB/H		BACT-PSD	2.16	T/YR		0.115	LB/T OF SLAG	
MI-0377	SEVERSTAL NORTH AMERICA, INC.	SEVERSTAL NORTH AMERICA, INC.	MI	182-05	331111	1/31/2006	INTEGRATED IRON AND STEEL PLANT	BLAST FURNACE STOVES	BLAST FURNACE GAS	24003	MMSCF/YR	Sulfur Dioxide (SO2)	NO CONTROLS FEASIBLE. COMPLIANCE VERIFICATION VIA CEMS.	14.37	LB/MMMSCF	WHEN B FURNACE OPERATING	BACT-PSD	16.62	LB/MMSCF	WHEN B FURNACE NOT OPERATING	0		
MI-0413	AK STEEL	AK STEEL CORPORATION	MI	182-05C	331111	5/12/2014	Iron and steel manufacturing facility	EUCFURNACE - C Blast Furnace which includes the blast furnace casthouse and stoves.	Nat. gas, BFG, pulv coal, coke	37841	MMCF/YR	Sulfur Dioxide (SO2)		179.65	LB/H	CALENDAR DAY AVG; BAGHOUSE STACK	BACT-PSD	193.6	LB/H	CALENDAR DAY AVG; STOVE STACK	0		
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	05/24/2010 ACT	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON PER YEAR. THE BASIC RAW MATERIALS FOR THE PIG IRON PRODUCTION PROCESS ARE IRON ORE, IN LUMP OR PELLET FORM; COAL; SINTER; AND FLUX, WHICH MAY BE LIMESTONE, DOLOMITE, OR SLAG. THE FACILITY WILL PROCESS THE COAL INTO METALLURGICAL-GRADE COKE FOR USE IN THE BLAST FURNACES AT DEDICATED COKE OVENS ON THE SITE. THE BLAST FURNACES THEMSELVES ARE CLOSED UNITS WITH VIRTUALLY NO ATMOSPHERIC EMISSIONS. THE COKE OVENS FOLLOW THE HEAT RECOVERY DESIGN. A SINTER PLANT WILL ALSO BE CONSTRUCTED AT THE SITE TO RECYCLE FINE MATERIALS AND DUSTS FOR INCREASED RAW MATERIAL EFFICIENCY. BY RECOVERING HEAT FROM THE COKING PROCESS AND COMBUSTING BLAST FURNACE GAS IN MULTIPLE BOILERS, THE MILL WILL PRODUCE ENOUGH ELECTRICITY TO COMPLETELY PROVIDE FOR FACILITY USAGE AND MAY ALSO PROVIDE SOME ELECTRICAL EXPORT TO THE PUBLIC UTILITY GRID.	STV-101-Blast Furnace 1 Hot Blast Stoves Common Stack	Blast Furnace Gas	627.04	MMBTU/H	Sulfur Dioxide (SO2)	No feasible control technology for Blast Furnace Gas. (BFG) Limit Natural Gas sulfur content	19.54	LB/H		BACT-PSD	28.19	T/YR		0		

Sulfur Dioxide (SO2)

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	PSD-LA-740	332111	05/24/2010 ACT	THE NUCOR STEEL LOUISIANA FACILITY WILL USE THE BLAST FURNACE PROCESS TO PRODUCE HIGH QUALITY PIG IRON. NUCOR PLANS FOR THE MILL TO REACH AN ANTICIPATED PEAK ANNUAL PRODUCTION RATE OF OVER SIX MILLION METRIC TONNES OF IRON PER YEAR. THE BASIC RAW MATERIALS FOR THE PIG IRON PRODUCTION PROCESS ARE IRON ORE, IN LUMP OR PELLET FORM; COAL; SINTER; AND FLUX, WHICH MAY BE LIMESTONE, DOLOMITE, OR SLAG. THE FACILITY WILL PROCESS THE COAL INTO METALLURGICAL-GRADE COKE FOR USE IN THE BLAST FURNACES AT DEDICATED COKE OVENS ON THE SITE. THE BLAST FURNACES THEMSELVES ARE CLOSED UNITS WITH VIRTUALLY NO ATMOSPHERIC EMISSIONS. THE COKE OVENS FOLLOW THE HEAT RECOVERY DESIGN. A SINTER PLANT WILL ALSO BE CONSTRUCTED AT THE SITE TO RECYCLE FINE MATERIALS AND DUSTS FOR INCREASED RAW MATERIAL EFFICIENCY. BY RECOVERING HEAT FROM THE COKING PROCESS AND COMBUSTING BLAST FURNACE GAS IN MULTIPLE BOILERS, THE MILL WILL PRODUCE ENOUGH ELECTRICITY TO COMPLETELY PROVIDE FOR FACILITY USAGE AND MAY ALSO PROVIDE SOME ELECTRICAL EXPORT TO THE PUBLIC UTILITY GRID.	STV-201-Blast Furnace 2 Hot Blast Stoves Common Stack	Blast Furnace Gas	627.04	MMBTU/H	Sulfur Dioxide (SO2)	No feasible control technology for Blast Furnace Gas. (BFG) Limit Natural Gas sulfur content	19.54	LB/H		BACT-PSD	28.19	T/H		0		
MI-0377	SEVERSTAL NORTH AMERICA, INC.	SEVERSTAL NORTH AMERICA, INC.	MI	182-05	331111	01/31/2006 ACT	INTEGRATED IRON AND STEEL PLANT	C FURNACE CASTHOUSE	PULVERIZED COAL, COKE	6700	T/D	Sulfur Dioxide (SO2)	NO FEASIBLE CONTROLS	14.65	LB/H	AVERAGING TIME PER TEST PROTOCOL	BACT-PSD	0			0		

Waste Heat Boiler

Nitrogen Oxides (NOx)

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
OH-0315	NEW STEEL INTERNATIONAL, INC., HAVERHILL	NEW STEEL INTERNATIONAL, INC.	OH	07-00587	331513	5/6/2008	STEEL MINI MILL, WITH 2 ELECTRIC ARC FURNACES AND A PRODUCTION RATE OF 4,409,248 TONS/YEAR. ***THIS FACILITY WAS NOT INSTALLED AS OF 10/09.***	WASTE HEAT BOILERS (6)	PULVERIZED COAL	60	MMBTU/H	Nitrogen Oxides (NOx)	SELECTIVE CATALYTIC REDUCTION AND LOW NOX BURNERS	48.61	LB/H	AS A ROLLING 3-HOUR AVERAGE	BACT-PSD	177.21	T/YR	AS A ROLLING 12-MONTH SUMMATION	0.081	LB/MMBTU	AS A ROLLING 3-HOUR AVERAGE

Nitrogen Oxides (NOx)

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
AL-0210	IPSCO STEEL INC.	IPSCO STEEL INC.	AL	503-8065-X003 MOD 1	331111	2/7/2005		REHEAT FURNACE	NATURAL GAS	450	mmbtu/h	Nitrogen Oxides (NOx)	LOW NOX BURNERS, 12 MONTH NATURAL GAS LIMIT -- 3.69 E+9 CUFT	77.4	LB/H		BACT-PSD	172	LB/MMBTU		0		
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	503-0095-X001 THRU X026	331111	8/17/2007	A NEW CARBON STEEL AND STAINLESS STEEL MILL TO PRODUCE VARIOUS GRADES AND/OR TYPES OF STEEL IN VARIOUS FORMS (COILS, SLITS, SHEETS, ETC.)	NATURAL GAS-FIRED REHEAT FURNACE (LA21) (MULTIPLE EMISSION POINTS)	NATURAL GAS	169	MMBTU/H	Nitrogen Oxides (NOx)	ULTRA LOW NOX AND LOW NOX BURNERS	0.085	LB/MMBTU		BACT-PSD	14.37	LB/H		0		
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	503-0095-X001 THRU X026	331111	8/17/2007	A NEW CARBON STEEL AND STAINLESS STEEL MILL TO PRODUCE VARIOUS GRADES AND/OR TYPES OF STEEL IN VARIOUS FORMS (COILS, SLITS, SHEETS, ETC.)	NATURAL GAS-FIRED REHEAT FURNACE (LA21) (MULTIPLE EMISSION POINTS)	NATURAL GAS	169	MMBTU/H	Nitrogen Oxides (NOx)	SCR	100	PPMVD	PARTS PER MILLION, VOLUMETRIC DRY	BACT-PSD	3.43	LB/H		0		
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	503-0095-X001 THRU X026	331111	8/17/2007	A NEW CARBON STEEL AND STAINLESS STEEL MILL TO PRODUCE VARIOUS GRADES AND/OR TYPES OF STEEL IN VARIOUS FORMS (COILS, SLITS, SHEETS, ETC.)	HOT STRIP MILL (MULTIPLE EMISSION POINTS)	NATURAL GAS	690	T/H	Nitrogen Oxides (NOx)	ULTRA LOW NOX BURNERS	0.085	LB/MMBTU	EACH FURNACE	BACT-PSD	40.1	LB/H	EACH FURNACE	0		
AR-0085	BLYTHEVILLE MILL	NUCOR-YAMATO STEEL COMPANY	AR	883-AOP-R5	331111	4/6/2005	PRODUCES STEEL BEAMS, PRIMARILY FROM STEEL SCRAP USING THE EAF PROCESS.	#1 REHEAT FURNACE (SN-02)	NATURAL GAS	300	MMBTU/H	Nitrogen Dioxide (NO2)	ULTRA LOW NOX BURNERS	51.3	LB/H		BACT-PSD	224.7	T/YR		0.07	LB/MMBTU	
FL-0283	JACKSONVILLE STEEL MILL	GERDAU AMERISTEEEL	FL	PSD-FL-349A	331513	5/5/2006	EXISTING SCRAP AND IRON AND STEEL RECYCLING (SECONDARY METAL PRODUCTION) FACILITY THAT PRODUCES STEEL REBAR, ROD AND WIRE. MAIN COMPONENTS OF THE PLANT INCLUDE: AN EXISTING FUCHS ELECTRIC ARC FURNACE (EAF); A LADLE METALLURGY FURNACE (LMF); A SCRAP HANDLING BUILDING; A ROKOP CONTINUOUS CASTER; A REBAR BILLET REHEAT FURNACE (BRF): A ROLLING MILL; A ROD MILL; AND, SLAG HANDLING AND STORAGE. PERMITTED CAPACITY IS 1,192,000 TONS PER CONSECUTIVE 12- MONTH OF TAPPED LIQUID STEEEL.	NEW BILLET REHEAT FURNACE	NATURAL GAS	160	T/YR	Nitrogen Oxides (NOx)	FIRING OF NATURAL GAS.	0.08	LB/MMBTU	SEE NOTE	BACT-PSD	0			0		
GA-0142	OSCEOLA STEEL CO.	OSCEOLA STEEL CO.	GA	3312-075-0024-P-01-0	331111	12/29/2010	Osceola Steel Co. plans to construct and operate a micro steel mill capable of producing 430,000 tons of scrape steel annually. The proposed micro steel mill project will include 1 electric arc furnace, 2 horizontal ladle pre-heaters, 1 vertical ladle heater, 2 Tundish pre-heaters, 1 reheat furnace, 2 castings machine torches, and 3 cooling towers. Natural gas will be fired in the electric are furnace, the reheat furnace, both horizontal ladle and Tundish pre-heaters, the vertical ladle heater, and the casting machine torches. The primary sources of emissions from the facility will be from the electric arc furnace and the reheat furnace.	Reheat Furnace	Natural Gas	75	MMBTU/H	Nitrogen Oxides (NOx)	Low NOx burners with FGR technology and good combustion/operating practices.	0.075	LB/T	3 HOUR STACK TESTING	BACT-PSD	0			0		
IA-0087	GERDAU AMERISTEEL WILTON	GERDAU AMERISTEEL WILTON	IA	PROJECT NUMBER 06-472	331111	5/29/2007	STEEL MINI-MILL THAT PRODUCES MERCHANT STEEL, SBQ BARS, FLATS, ANGLES, AND REBAR.	BILLET REHEAT FURNACE	NATURAL GAS	145.5	MMBTU/H	Nitrogen Oxides (NOx)	24 ULTRA LOW NOX BURNERS	110.23	LB/MMCF	AVG OF THREE (3) TEST RUNS	BACT-PSD	22.45	T/YR	ROLLING 12 MONTH TOTAL	0		
IL-0126	NUCOR STEEL KANKAKEE, INC.	NUCOR STEEL KANKAKEE, INC.	IL	18060014	331111	11/1/2018	Nucor Steel produces steel billets from scrap metal in an electric arc furnace shop. The billets produced at the plant are either further processed at the rolling mills. The rolling mills at the plant produce steel bars and rods in various shapes and sizes from the billets produced at the plant.	Natural Gas-Fired Reheat Furnace	Natural Gas	125.5	mmBtu/hr	Nitrogen Oxides (NOx)	Good combustion practices and low-NOx burners	0.07	LBS/MMBTU	DAILY (24-HR) AVERAGE	BACT-PSD	11.3	LBS/HR	AVERAGE VALID TEST RUN	0		
LA-0309	BENTELER STEEL TUBE FACILITY	BENTELER STEEL / TUBE MANUFACTURING CORPORATION	LA	PSD-LA-774(M1)	331111	6/4/2015	A facility to produce 600,000 metric tons per year of seamless steel pipe from purchased billets. A steel production facility (including an electric arc furnace (EAF)) was added.	Shell Reheat Furnace - S04	natural gas	79.7	mm btu/hr	Nitrogen Oxides (NOx)	ULNB	0.075	LB/MM BTU		BACT-PSD	0			0		
MI-0417	GERDAU MACSTEEL, INC.	GERDAU MACSTEEL, INC.	MI	102-12A	331111	10/27/2014	Steel mill	EUBILLET-REHEAT (Walking Beam Billet Reheat Furnace)	natural gas ultra low NOx burners	260.7	MMBTU/H total burner capacity	Nitrogen Oxides (NOx)	Ultra-Low NOx burners and good combustion practices.	0.07	LB/MMSCF	TEST PROTOCOL	BACT-PSD	18.3	LB/H	TEST PROTOCOL	0		
NJ-0087	GERDAU SAYREVILLE	GERDAU	NJ	18052/BOP150001	331111	3/26/2018	Steel mini-mill	Billet Reheat Furnace	Natural gas	1178	MMSCF/YR	Nitrogen Oxides (NOx)	Low NOx Burners	0.1	LB/MMBTU	AV OF THREE STACK TEST RUNS ANNUALLY	RACT	17.3	LB/H	AV OF THREE STACK TEST RUNS ANNUALLY	0		
OH-0316	V & M STAR	V & M STAR	OH	P0103660	331111	9/23/2008	STEEL MINI-MILL PLANT, EXPANSION OF AN EXISTING PLANT PRODUCTION OF SEAMLESS STEEL TUBES.	BILLET PREHEAT FURNACE	NATURAL GAS	0.18	MMSCF/H	Nitrogen Oxides (NOx)	ULTRA-LOW NOX BURNERS	12.6	LB/H		BACT-PSD	30.4	T/YR	AS A ROLLING 12-MONTH SUMMATION	0.07	LB/MMBTU	
OH-0316	V & M STAR	V & M STAR	OH	P0103660	331111	9/23/2008	STEEL MINI-MILL PLANT, EXPANSION OF AN EXISTING PLANT PRODUCTION OF SEAMLESS STEEL TUBES.	BILLET REHEAT FURNACE	NATURAL GAS	290	MMBTU/H	Nitrogen Oxides (NOx)	ULTRA-LOW NOX BURNERS	29	LB/H		BACT-PSD	89.3	T/YR	AS A ROLLING 12-MONTH SUMMATION	0.1	LB/MMBTU	
OH-0331	AK STEEL CORPORATION MANSFIELD WORKS	AK STEEL CORPORATION	OH	03-17463	331111	1/11/2010	STEEL SHOP USING ELECRIC ARC FUNRACES. SEE A MODIFICATION IN OH-0335.	Slab Reheat Furnace	Natural Gas	1138800	MMBtu/YR	Nitrogen Oxides (NOx)		0.14	LB/MMBTU	CALCULATED FROM AP-42 SECTION 1.4	N/A	79.72	T/YR	PER ROLLING 12 MONTHS	0		
OH-0341	NUCOR STEEL MARION, INC.	NUCOR STEEL	OH	P0105283	331111	12/23/2010	Steel Facility, Non-integrated mini-mill producing carbon steel bar stock, angle reinforcing rod, and highway products. This is a modification to OH-0294.	Reheat furnace for steel billet	Natural gas	184	MMBtu/H	Nitrogen Oxides (NOx)	Low NOx burners	27.6	LB/H		BACT-PSD	120.89	T/YR	PER ROLLING 12 MONTHS	0		

U. S. Steel Gary Works
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix A: RBLC Search Summary for Pertinent Emission Units at Similar Sources
Reheat Furnace

Nitrogen Oxides (NOx)

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS CODE	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	UNITS	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
SC-0128	NUCOR STEEL CORPORATION (DARLINGTON PLANT)	NUCOR CORPORATION	SC	0820-0001-DF	331111	12/29/2006	THIS FACILITY PRODUCES BAR PRODUCT PRIMARILY FROM STEEL SCRAP AND SCRAP SUBSTITUTES USING AN ELECTRIC ARC FURNACE.	REHEAT FURNACE NO.2	NATURAL GAS	180	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNERS	0.075	LB/MMBTU		BACT-PSD	0			0		
TX-0503	ALUMAX SECONDARY ALUMINUM SMELTER	ALUMAX MILL PRODUCT	TX	PSD-TX 886 AND 9476	331314	5/15/2006	THIS FACILITY PROCESSES BOTH ALUMINUM SCRAP AND CLEAN INGOTS WHICH ARE THE RAW MATERIAL FOR A ROLLING MILL. ALUMINUM SCRAP AND CLEAN ALUMINUM INGOTS ARE RECEIVED ON SITE AND THEN CHARGED INTO EITHER WELL FURNACES OR A DOME FURNACE. THE MOLTEN ALUMINUM IS TRANSFERRED FROM THE MELT FURNACES TO HOLDING FURNACES AND THEN FURTHER TRANSFERRED TO INGOT CASTERS. CAST INGOTS ARE PROCESSED THRU A SCALPER AND THEN INTO PREHEAT FURNACES. FROM THE PREHEAT FURNACES THE INGOTS ARE PROCESSED BY THE HOT ROLLING MILL, THE COLD ROLLING MILL, AND ANNEALING OVENS. ROLLED ALUMINUM SHEET IS THEN PROCESSED THRU TENSION LEVELERS AND SOME IS COATED.	PREHEAT FURNACE NO 2				Nitrogen Oxides (NOx)		1.6	LB/H		BACT-PSD	7.01	T/YR		0		
TX-0503	ALUMAX SECONDARY ALUMINUM SMELTER	ALUMAX MILL PRODUCT	TX	PSD-TX 886 AND 9476	331314	5/15/2006	THIS FACILITY PROCESSES BOTH ALUMINUM SCRAP AND CLEAN INGOTS WHICH ARE THE RAW MATERIAL FOR A ROLLING MILL. ALUMINUM SCRAP AND CLEAN ALUMINUM INGOTS ARE RECEIVED ON SITE AND THEN CHARGED INTO EITHER WELL FURNACES OR A DOME FURNACE. THE MOLTEN ALUMINUM IS TRANSFERRED FROM THE MELT FURNACES TO HOLDING FURNACES AND THEN FURTHER TRANSFERRED TO INGOT CASTERS. CAST INGOTS ARE PROCESSED THRU A SCALPER AND THEN INTO PREHEAT FURNACES. FROM THE PREHEAT FURNACES THE INGOTS ARE PROCESSED BY THE HOT ROLLING MILL, THE COLD ROLLING MILL, AND ANNEALING OVENS. ROLLED ALUMINUM SHEET IS THEN PROCESSED THRU TENSION LEVELERS AND SOME IS COATED.	PREHEAT FURNACE NO 1				Nitrogen Oxides (NOx)		9.1	LB/H		BACT-PSD	39.86	T/YR		0		
TX-0503	ALUMAX SECONDARY ALUMINUM SMELTER	ALUMAX MILL PRODUCT	TX	PSD-TX 886 AND 9476	331314	5/15/2006	THIS FACILITY PROCESSES BOTH ALUMINUM SCRAP AND CLEAN INGOTS WHICH ARE THE RAW MATERIAL FOR A ROLLING MILL. ALUMINUM SCRAP AND CLEAN ALUMINUM INGOTS ARE RECEIVED ON SITE AND THEN CHARGED INTO EITHER WELL FURNACES OR A DOME FURNACE. THE MOLTEN ALUMINUM IS TRANSFERRED FROM THE MELT FURNACES TO HOLDING FURNACES AND THEN FURTHER TRANSFERRED TO INGOT CASTERS. CAST INGOTS ARE PROCESSED THRU A SCALPER AND THEN INTO PREHEAT FURNACES. FROM THE PREHEAT FURNACES THE INGOTS ARE PROCESSED BY THE HOT ROLLING MILL, THE COLD ROLLING MILL, AND ANNEALING OVENS. ROLLED ALUMINUM SHEET IS THEN PROCESSED THRU TENSION LEVELERS AND SOME IS COATED.	PREHEAT FURNACE NO 3				Nitrogen Oxides (NOx)		4.22	LB/H		BACT-PSD	18.5	T/YR		0		
TX-0705	STEEL MINIMILL FACILITY	STRUCTURAL METALS INC	TX	PSDTX708M6 8248	331111	7/24/2014	The primary purpose of the permit amendment is to authorize a number of physical and operational changes to increase the annual production rate through the electric arc furnace (EAF) and associated material handling sources at the mill. Specifically, the amendment will increase the melt shop production to 1,300,000 tpy.	Rolling Mill Billet Reheat Furnace	Natural Gas	1300000	tons/year	Nitrogen Oxides (NOx)	Ultra-low NOX burners.	0.073	LB/MMBTU		BACT-PSD	0			0		

Appendix B

Air Permit Summary for Similar Sources

U. S. Steel Gary Works
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix B: Air Permit Summary for Similar Sources

	Sinter Plant						
	Emission Unit Description	NOx			SO2		
		Controls	Limit	Comments	Controls	Limit	Comments
USS Gary Works	ISS10379 Sinter Strand (No. 3 Sinter Plant) 225 tons sinter/hr 50 mmbtu/hr (burners combined) - natural gas	None	95.5 MMSCF	Natural gas usage shall be less than limit in the No. 3 Sinter Plant Sinter Strand Windbox reheat burners ISB001 and ISB003 per twelve (12) consecutive month period	Quench Reactor, Dry Venturi Scrubber	200 lb/hr	
	ISS30381 Sinter Strand (No. 3 Sinter Plant) 225 tons sinter/hr 50 mmbtu/hr (burners combined) - natural gas	None	95.5 MMSCF	Natural gas usage shall be less than limit in the No. 3 Sinter Plant Sinter Strand Windbox reheat burners ISB001 and ISB003 per twelve (12) consecutive month period	Quench Reactor, Dry Venturi Scrubber	200 lb/hr	
AM Indiana Harbor East	1959 Sinter Plant 1.4 Mmton/yr input	None	None		None	180 lb/hr	Pursuant to 326 IAC 7-4.1-11(a)(13)
AM Indiana Harbor West	1958 Sinter Plant (not present in 2020 permit mod) 2 Mmton/yr Sinter	None	None		Wet venturi scrubbers	240 lb/hr	Pursuant to 326 IAC 7-4.1-10(a)(3)
AM Burns Harbor	1968 Continuous Sintering Process Plant 535 tons sinter/hr	None	None		Venturi scrubber	None	
Nucor St. James	Not constructed Sinter Plant 3.03 Mmtons/yr Natural gas	None	0.495 lb/ton finished sinter	LAC 33:III.509	Lime Spray Drying Scrubber	2000 ppmv 100 mg/DSCM	LAC 33:III.1503.C: 3-hr average LAC 33:III.509, BACT
USS Clairton	Facility does not have a sinter plant						
AK Dearborn	Facility does not have a sinter plant						
AK Middleton	Facility does not have a sinter plant						
AM Cleveland	Facility does not have a sinter plant						
USS Edgar Thompson	Facility does not have a sinter plant						
USS East Chicago	Facility does not have a sinter plan						

U. S. Steel Gary Works
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix B: Air Permit Summary for Similar Sources

	Blast Furnace						
	Emission Unit Description	NOx			SO2		
		Controls	Limit	Comments	Controls	Limit	Comments
USS Gary Works	IDBF0369 No. 14 Blast Furnace Comprised of three No. 14 Blast Furnace Stoves (IDST0359) 450 tons metal production/hr 700 MMBtu/hr max HI total Natural gas / Pulverized coal (80 tons/hr) / Oil (150	None	None		None	0.134 lb/MMBtu	Limit on: Blast Furnace No. 14 Stove Stack
						93.5 lb/hr total	Limit on: Blast Furnace No. 14 Stove Stack
						115 lb/hr	Limit on: Blast Furnace No. 14 Casthouse Baghouse
AM Indiana Harbor East	1980 No. 7 Blast Furnace Comprised of four No. 7 Blast Furnace Stoves 4.417 Mmtons/yr metal production 953 MMBtu/hr max HI total Pulverized coal (132 tons/hr) / Natural Gas / Blast Furnace Gas	None	None		None	0.195 lb/MMBtu	Pursuant to 326 IAC 7-4.1-11(a) Limit on: Blast Furnace No. 7 Stove Stack
						162 lb/hr	Pursuant to 326 IAC 7-4.1-11(a) Limit on: Blast Furnace No. 7 Stove Stack
						0.22 lb/ton	Pursuant to 326 IAC 7-4.1-11(a) Limit on: Blast Furnace
						50.4 lb/hr	Pursuant to 326 IAC 7-4.1-11(a) Limit on: Blast Furnace No. 7 Casthouse
AM Indiana Harbor West	1953 No. 3 Blast Furnace Comprised of three No. 3 Blast Furnace Stoves 4.5552 Mmtons/yr input 441 MMBtu/hr max HI total	None	None		None	0.29 lb/MMBtu	Pursuant to 326 IAC 7-4.1-10(a)(4)(A) Limit on: Blast Furnace No. 3 Stove Stack
						127.89 lb/hr	Pursuant to 326 IAC 7-4.1-10(a)(4)(A) Limit on: Blast Furnace No. 3 Stove Stack
	1967 No. 4 Blast Furnace Comprised of three No. 4 Blast Furnace Stoves 5.490836 Mmtons/yr input 486 MMBtu/hr max HI total	None	None		None	0.29 lb/MMBtu	Pursuant to 326 IAC 7-4.1-10(a)(4)(B) Limit on: Blast Furnace No. 4 Stove Stack
						140.94 lb/hr	Pursuant to 326 IAC 7-4.1-10(a)(4)(B) Limit on: Blast Furnace No. 4 Stove Stack
						0.18 lb/ton	Pursuant to 326 IAC 7-4.1-10(a)(6) Limit on : Blast Furnace No. 4 Casting
						69.9 lb/hr	Pursuant to 326 IAC 7-4.1-10(a)(6) Limit on : Blast Furnace No. 4 Casting
	2 Ladle Burners 36 MMBtu/hr max HI total	None	None		None	None	
	Railcar Thaw Shed Heater 50.4 MMBtu/hr max HI total	None	None		None	None	
AM Burns Harbor	1971 C Blast Furnace Consisting of C Blast Furnace Stoves 623 tons/hr iron (total with D Blast Furnace) 660 MMBtu/hr max HI total	None	None		None	None	
	1968 D Blast Furnace Consisting of D Blast Furnace Stoves 623 tons/hr iron (total with C Blast Furnace) 660 MMBtu/hr max HI total	None	None		None	None	
Nucor St. James	Not Constructed Blast Furnace 1 1,088 MMBtu/hr Natural gas, Blast furnace gas	Low NOx fuels	0.06 lb/MMBtu	LAC 33:III.509, BACT	Low Sulfur fuels	0.002 gr/dscf Natural Gas (SO2 as H2S) 0.00874 gr/dscf BFG	LAC 33:III.509, BACT: Sulfur content in natural gas
	Not Constructed Casthouse No. 1	None	None		None	0.040 lb/ton hot metal	LAC 33:III.509, BACT
	Not Constructed Blast Furnace 2 1,088 MMBtu/hr Natural gas, Blast furnace gas	Low NOx fuels	0.06 lb/MMBtu	LAC 33:III.509, BACT	Low Sulfur fuels	0.002 gr/dscf Natural Gas (SO2 as H2S)	LAC 33:III.509, BACT: Sulfur content in natural gas
	Not Constructed Casthouse No. 2	None	None		None	0.040 lb/ton hot metal	LAC 33:III.509, BACT
USS Clairton	Facility does not have a blast furnace						
AK Dearborn	1/1/1922 EUBFURNACE (part of FGB&CFURNACES), group of 4 stoves with a common stack, cast house emission control system (collection hoods, baghouse, stack), a blast furnace gas scrubber and dust collector, semi-clean bleeder, and dirty gas bleeder. 3,321,500 tons iron/yr (material limit on FGB&CFURNACES) Natural gas, Blast furnace gas	Low-NOx Stove Technology	25.74 tons/yr (12mo rolling)	Limit on: FGB&CFURNACES baghouse stacks R336.2801 - R336.2804 -- PSD	None	1,188 tpy (12mo rolling)	Limit on: FGB&CFURNACES baghouse and stove stacks R336.2803, R336.2804 -- PSD
	1/1/1948, 10/1/2007 EUCFURNACE (part of FGB&CFURNACES), group of 4 stoves with a common		439.2 tons/yr (12mo rolling)	Limit on: FGB&CFURNACES stove stacks R336.2801 - R336.2804 -- PSD			

U. S. Steel Gary Works
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix B: Air Permit Summary for Similar Sources

	Blast Furnace						
	Emission Unit Description	NOx			SO2		
		Controls	Limit	Comments	Controls	Limit	Comments
AK Middleton	P925 No. 3 Blast Furnace 740 tons metal production/hr	None	None		None	None	
AM Cleveland	P903 Blast Furnace C5	None	0.06 lbs/MMBtu	for furnace stoves	None	33 lb/hr	from the blast furnace casthouse when combusting coke oven gas d. These emission limitations are not applicable because coke oven gas is no longer capable of being burned in this emissions unit.
						53 lb/hr	from the blast furnace stoves when combusting coke oven gas d. These emission limitations are not applicable because coke oven gas is no longer capable of being burned in this emissions unit.
	P904 Blast Furnace C6	None	0.06 lbs/MMBtu	for furnace stoves	None	33 lb/hr	A maximum of 390 grains of hydrogen sulfide per 100 dry standard cubic feet of coke oven gas, and the daily average not to exceed 33 lbs of SO2 per hour from the blast furnace casthouse when combusting coke oven gas.
						53 lb/hr	Maximum of 390 grains of hydrogen sulfide per 100 dscf of coke oven gas and the daily average not to exceed 53 lbs SO2/hr from the blast furnace stoves when combusting coke oven gas.
USS Edgar Thompson	P001a Blast Furnace No. 1 Casthouse 1,752,000 tpy (production capacity) Coke, Iron-bearing materials, fluxes	None	None		None	None	
	P001b Blast Furnace No. 1 Stoves 495 MMBtu/hr BFG, COG, Natural Gas	None	None		None	1. 353.03 lb/hr 2. 108.41 tpy 3. A = 1.7 E^(-0.14)	1. Applies to each set of stoves (No. 1 Blast furnace stoves & No. 3 Blast furnace stoves) Permit References: (§2104.03.a.2.B, §2104.02.b, §2103.12.a.2.B) 2. Applies to each set of stoves (No. 1 Blast furnace stoves & No. 3 Blast furnace stoves) Permit References: (§2104.03.a.2.B, §2104.02.b, §2103.12.a.2.B) 3. "The permittee shall not operate No. 1 or No. 3 Blast furnace stoves, in such a manner that emission of sulfur oxides, expressed as sulfur dioxide (SO2), exceed the rate determined by the formula: (§2104.03.a.2.B) A = allowable emissions in lbs/Mmbtu of actual heat input E = actual heat input in MMBtu/hr
	P002b Base Furnace No. 3 Stoves 495 MMBtu/hr BFG, COG, Natural Gas	None	None		None		
	P001c BFG Flare 3 MMcfh BFG	None	None		None		
	P002a Blast Furnace No. 3 Casthouse 1,752,000 tpy (production capacity) Coke, Iron-bearing materials, fluxes	None	None		None		
USS East Chicago	Facility does not have a blast furnace						

U. S. Steel Gary Works

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix B: Air Permit Summary for Similar Sources

<table>
<tr><th></th><th colspan="4">Strip Mill Reheat Furnace and Waste Heat Recovery Boiler</th></tr>
<tr><th></th><th rowspan="2">Emission Unit Description</th><th colspan="3">NOx</th></tr>
<tr><th></th><th>Controls</th><th>Limit</th><th>Comments</th></tr>
<tr><td rowspan="7">USS Gary Works</td><td>RMV00504 84 in. Hot Strip Mill Boilers (No. 1 and No. 2)
856 tons metal processing/hr
Natural gas</td><td>None</td><td>None</td><td></td></tr>
<tr><td>RB1B0508 Waste Heat boiler No. 1
226 MMBtu/hr max HI (ea.)
Natural gas</td><td>None</td><td>None</td><td></td></tr>
<tr><td>RB2B0509 Waste Heat Boiler No. 2
226 MMBtu/hr max HI (ea.)
Natural gas</td><td>None</td><td>None</td><td></td></tr>
<tr><td>RMF10500 Reheat Furnace No. 1 (Hot Strip Mill Furnace)
600 MMBtu/hr max HI (ea.)
Natural gas</td><td>None</td><td>None</td><td></td></tr>
<tr><td>RMF20501 Reheat Furnace No. 2 (Hot Strip Mill Furnace)
600 MMBtu/hr max HI (ea.)
Natural gas</td><td>None</td><td>None</td><td></td></tr>
<tr><td>RMF30502 Reheat Furnace No. 3 (Hot Strip Mill Furnace)
600 MMBtu/hr max HI (ea.)
Natural gas</td><td>None</td><td>None</td><td></td></tr>
<tr><td>RMF40503 Reheat Furnace No. 4 (Hot Strip Mill Furnace)
600 MMBtu/hr max HI (ea.)
Natural gas</td><td>None</td><td>None</td><td></td></tr>
<tr><td rowspan="3">AM Indiana Harbor East</td><td>2001 No. 4 Walking Beam Furnace
720 MMBtu/hr max HI (ea.)
Natural Gas</td><td>Low-NOx burners</td><td rowspan="3">35 lb/MMSCF</td><td rowspan="3">Prevention of Significant Deterioration (PSD) and Emission Offset Minor Limit [326 IAC 2-2][326 IAC 2-3]: Total for all furnaces</td></tr>
<tr><td>1995 No. 5 Walking Beam Furnace
685.6 MMBtu/hr max HI (ea.)
Natural Gas</td><td>None</td></tr>
<tr><td>1995 No. 6 Walking Beam Furnace
685.6 MMBtu/hr max HI (ea.)
Natural Gas</td><td>None</td></tr>
<tr><td rowspan="3">AM Indiana Harbor West</td><td>1968 No. 1 Reheat Furnace
427 MMBtu/hr max HI (ea.)
Natural Gas</td><td>None</td><td>None</td><td></td></tr>
<tr><td>1968 No. 2 Reheat Furnace
427 MMBtu/hr max HI (ea.)
Natural Gas</td><td>None</td><td>None</td><td></td></tr>
<tr><td>1968 No. 3 Reheat Furnace
427 MMBtu/hr max HI (ea.)
Natural Gas</td><td>None</td><td>None</td><td></td></tr>
</table>

U. S. Steel Gary Works

Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls

Appendix B: Air Permit Summary for Similar Sources

	Strip Mill Reheat Furnace and Waste Heat Recovery Boiler			
	Emission Unit Description	NOx		
		Controls	Limit	Comments
AM Burns Harbor	1966 Reheat Furnace No. 1 730 MMBtu/hr max HI (ea.) natural gas, coke oven gas, and/or propane	None	None	
AM Burns Harbor	1966 Reheat Furnace No. 2 730 MMBtu/hr max HI (ea.) natural gas, coke oven gas, and/or propane	None	None	
AM Burns Harbor	1966 Reheat Furnace No. 3 730 MMBtu/hr max HI (ea.) natural gas, coke oven gas, and/or propane	None	None	
AM Burns Harbor	Approved in 2017 - HSM WBF No. 1 820 MMBtu/hr max HI (ea.) Natural Gas	Low-NOx burners	None	
AM Burns Harbor	Approved in 2017 - HSM WBF No. 2 820 MMBtu/hr max HI (ea.) Natural Gas	Low-NOx burners	None	
Nucor St. James	Facility as proposed did not have reheat furnaces or waste heat recovery boilers			
USS Clairton	Facility as proposed did not have reheat furnaces or waste heat recovery boilers			
AK Dearborn	1/1/1979 EUREHEATFURN1 - slab reheat furnace 1 oil shall not be used	None	0.11 lbs/MMBtu	R 336.2081 (ee) / 336.2082(4) -- PSD
AK Dearborn	1/1/1974 EUREHEATFURN2 - slab reheat furnace 2 oil shall not be used			
AK Dearborn	1/1/1974 EUREHEATFURN3 - slab reheat furnace 3 oil shall not be used			
AK Middleton	P094 Hot Strip Mill	None	None	
AK Middleton	P009 No. 3 Slab Reheat Furnace/Waste Heat Boiler 598 MMBtu/hr Slab Furnace 305 MMBtu/hr Waste Heat Boiler Natural gas, fuel oil, coke oven gas	None	None	
AK Middleton	P010 No. 2 Slab Reheat Furnace/Waste Heat Boiler 598 MMBtu/hr Slab Furnace 305 MMBtu/hr Waste Heat Boiler Natural gas, fuel oil, coke oven gas	None	None	
AK Middleton	P011 No. 1 Slab Reheat Furnace/Waste Heat Boiler 598 MMBtu/hr Slab Furnace 305 MMBtu/hr Waste Heat Boiler Natural gas, fuel oil, coke oven gas	None	None	
AK Middleton	P012 No. 4 Slab Reheat Furnace/Waste Heat Boiler 598 MMBtu/hr Slab Furnace 305 MMBtu/hr Waste Heat Boiler Natural gas, fuel oil, coke oven gas	None	None	

U. S. Steel Gary Works
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix B: Air Permit Summary for Similar Sources

	Strip Mill Reheat Furnace and Waste Heat Recovery Boiler			
	Emission Unit Description	NOx		
		Controls	Limit	Comments
AM Cleveland	P046-P048 80" hot strip mill reheat furnaces 1,2,3 630 MMBtu/hr (each) Natural gas, fuel oil backup	Low NOx burners	0.35 lbs/MMBtu	for each furnace, OAC rule 3745-110-03(N) (as of 5/12/2011)
	P265 Walking beam furnace 615 MMBtu/hr Natural gas	None	0.4 lbs/MMBtu	shall not exceed the lesser of 0.4 lb/mmBtu of actual heat input and 1.2 times the actual rate as determined by testing
USS Edgar Thompson	Facility does not have reheat furnaces or waste heat recovery boilers			
USS East Chicago	Facility does not have reheat furnaces or waste heat recovery boilers			

Appendix C

Unit-specific Screening Level Cost Summaries for NO_X Emission Control Measures

Appendix C.1

84” Hot Strip Mill Reheat Furnaces No. 1 through No. 4

U. S. Steel Gary Works
Regional Haze Four-Factor Analysis for NO_X and SO_2 Emission Controls
Appendix C.1 - Table C.1-1: Cost Summary
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

NO_x Control Cost Summary (emissions and costs are for each furnace individually)

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton
Low NOx Burners (LNB)	65%	112.7	210.6	$23,010,000	$2,977,781	$14,142

U. S. Steel Gary Works
Regional Haze Four-Factor Analysis for NO_X and SO_2 Emission Controls
Appendix C.1 - Table C.1-2: Summary of Utility, Chemical and Supply Costs
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4
Note: emissions and costs are for each furnace individually **Study Year** 2020

Item	2020 Unit Cost	Units	Cost	Year	Data Source
Operating Labor	68	$/hr	60	2016	EPA SCR Control Cost Manual Spreadsheet
Maintenance Labor	68	$/hr			Assumed to be equivalent to operating labor
Other					
Sales Tax	7%			2020	Indiana sales tax rate
Interest Rate	5.50%			2016	EPA SCR Control Cost Manual Spreadsheet
Contingencies	30%	of purchased equip cost (B)			U. S. Steel Estimate
Markup on capital investment (retrofit factor)	0%				EPA Cost Control Cost Manual Chapter 2
Operating Information					
Annual Op. Hrs	8,760	Hours			Assumed
Utilization Rate	100%				Assumed
Design Capacity	600.0	MMBTU/hr			Design Capacity
Equipment Life	20	yrs			Assumed
Plant Elevation	607	Feet above sea level			Plant elevation
	Baseline Emissions				
Pollutant	**Ton/Year**				
Nitrous Oxides (NOx)	323.3				Combined 2028 emissions for all four reheat furnaces, distributed evenly across each furnace
LNB - NO_x Performance	0.10	lb/MMBtu			Vendor estimated burner performance HHV, calculated from LHV factor from vendor
Baseline NOx performance	0.27	lb/MMBtu			280 lb/MMscf converted to lb/MMBtu assuming 1020 btu/scf for natural gas
Control efficiency	65%				Calculated

U. S. Steel Gary Works

Regional Haze Four-Factor Analysis for NO_X and SO_2 Emission Controls

Appendix C.1 - Table C.1-3: NO_x Control - Low NOx Burners (LNB)

84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

Note: emissions and costs are for each furnace individually

Desgin Capacity	600	MMBtu/hr
Expected Utiliztion Rate	100%	
Expected Annual Hours of Operation	8,760	Hours
Annual Interest Rate	5.5%	
Expected Equipment Life	20	yrs

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment Total (B)								6,100,000
Installation Total								10,000,000
Total Direct Capital Cost, DC								16,100,000
Total Indirect Capital Costs, IC								6,910,000
Total Capital Investment (TCI) = DC + IC								**23,010,000**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						82,450
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						2,895,331
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**2,977,781**

EMISSION CONTROL COST EFFECTIVENESS

Pollutant	**Baseline Emis. T/yr**	**Cont. Emis.**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10		-			-	NA
Total Particulates		-			-	NA
Nitrous Oxides (NOx)	323.3		0.10	112.7	210.6	14,142
Sulfur Dioxide (SO_2)		-			-	NA

Notes & Assumptions

1 Equipment costs from vendor, installation based on U. S. Steel previous similar project experience
2 Purchased equipment includes 46 low-NOX burners, new combustion air fan, instrumentation, PLC, control valves, controls system and equipment to maintain NFPA compliance per code.
3 Installation includes, but is not limited to: installation of upgraded burner ports including shell and refractory work, natural gas header, combustion air fan and ducts power system modifications, and upgrades/repairs to 50-year old infrastructure
4 Retrofit Costs are intended to address undefined additional costs such as: specific design and space constraints of the facility, structural improvements/repairs that may be necessary, and asbestos/lead paint abatement.
5 Assumed 0.1 and 0.5 hr/shift respectively for operator and maintenance labor
6 Controlled emission factor based on vendor estimated burner performance

U. S. Steel Gary Works
Regional Haze Four-Factor Analysis for NO_X and SO_2 Emission Controls
Appendix C.1 - Table C.1-3: NOx Control - Low NOx Burners (LNB)
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**5,000,000**
Purchased Equipment Costs			
Instrumentation	10%	of purchased equip cost	500,000
Sales Taxes	7.0%	of purchased equip cost	350,000
Freight	5%	of purchased equip cost	250,000
Purchased Equipment Total (B)	22%		**6,100,000**
Installation			
Infrastructure repairs/replacement	50%	of purchased equip cost	2,500,000
Construction & field expenses	100%	of purchased equip cost and infrastructure cost	7,500,000
Installation Total			**10,000,000**
Total Direct Capital Cost, DC			**16,100,000**
Indirect Capital Costs			
Construction Management and Indirects	10%	Equipment, Infrastructure, and Construction Costs	1,500,000
Start-up	1%	of purchased equip cost	50,000
Performance test	1%	of purchased equip cost	50,000
Model Studies	NA	of purchased equip cost	NA
Retrofit costs	30%	of total cost	5,310,000
Total Indirect Capital Costs, IC			**6,910,000**
Total Capital Investment (TCI) = DC + IC			**23,010,000**
Site Preparation, as required		Included above	NA
Buildings, as required		Included above	NA
Site Specific - Other		Included above	
Total Site Specific Costs			**0**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**23,010,000**
Total Capital Investment (TCI)			**23,010,000**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	67.53	$/Hr, 0.1 hr/8 hr shift, 8760 hr/yr	7,395
Supervisor	15%	15% of Operator Costs	1,109
Maintenance (2)			
Maintenance Labor	67.53	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr	36,973
Maintenance Materials	100%	of maintenance labor costs	36,973
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**82,450**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	49,470
Administration (2% total capital costs)	2%	of total capital costs (TCI)	460,200
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	230,100
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	230,100
Capital Recovery	8%	for a 20- year equipment life and a 5.5% interest rate	1,925,461
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**2,895,331**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**2,977,781**

U. S. Steel Gary Works

Regional Haze Four-Factor Analysis for NO_X and SO_2 Emission Controls

Appendix C.1 - Table C.1-3: NOx Control - Low NOx Burners (LNB)

84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:
N/A

Replacement Parts & Equipment:
N/A

Electrical Use
N/A

Reagent Use & Other Operating Costs
N/A

Operating Cost Calculations — **Annual hours of operation:** **8,760** — **Utilization Rate:** **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	67.53	$/Hr	0.1	hr/8 hr shift	110	7,395	$/Hr, 0.1 hr/8 hr shift, 8760 hr/yr
Supervisor	15%	of Op.			NA	1,109	15% of Operator Costs
Maintenance							
Maint Labor	67.53	$/Hr	0.5	hr/8 hr shift	548	36,973	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	36,973	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.073	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 8760 hr/yr, 100% utilization
Natural Gas	6.15	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8760 hr/yr, 100% utilization
Water	5.13	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8760 hr/yr, 100% utilization

Appendix C.2

Waste Heat Boiler No. 1

U. S. Steel Gary Works
Regional Haze Four-Factor Analysis for NO_X and SO_2 Emission Controls
Appendix C.2 - Table C.2-1: Cost Summary
Waste Heat Boiler No. 1

NO_x Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton
Low NOx Burners (LNB)	65%	31.0	58.0	$1,806,740	$355,376	$6,130

U. S. Steel Gary Works
Regional Haze Four-Factor Analysis for NO_X and SO_2 Emission Controls
Appendix C.2 - Table C.2-2: Summary of Utility, Chemical and Supply Costs
Waste Heat Boiler No. 1

Study Year 2020

Item	2020 Unit Cost	Units	Cost	Year	Data Source
Operating Labor	68	$/hr	60	2016	EPA SCR Control Cost Manual Spreadsheet
Maintenance Labor	68	$/hr			Assumed to be equivalent to operating labor
Other					
Sales Tax	7%			2020	Indiana sales tax rate
Interest Rate	5.50%			2016	EPA SCR Control Cost Manual Spreadsheet
Contingencies	30%	of purchased equip cost (B)			U. S. Steel Estimate
Markup on capital investment (retrofit factor)	0%				EPA Cost Control Cost Manual Chapter 2
Operating Information					
Annual Op. Hrs	8,760	Hours			Assumed
Utilization Rate	100%				Assumed
Design Capacity	226	MMBTU/hr			Design Capacity
Equipment Life	20	yrs			Assumed
Plant Elevation	607	Feet above sea level			Plant elevation
	Baseline Emissions				
Pollutant	**Ton/Year**				
Nitrous Oxides (NOx)	89.0				Estimated 2028 emissions
LNB - NO_x Performance	0.10	lb/MMBtu			Assuming similar performance to reheat furnace low-NOX burner estimate
Baseline NOx performance	0.27	lb/MMBtu			280 lb/MMscf converted to lb/MMBtu assuming 1020 btu/scf for natural gas
Control efficiency	65%				Calculated

U. S. Steel Gary Works
Regional Haze Four-Factor Analysis for NO_X and SO_2 Emission Controls
Appendix C.2 - Table C.2-3: NO_x Control - Low NOx Burners (LNB)
Waste Heat Boiler No. 1

Desgin Capacity	226	MMBtu/hr
Expected Utiliztion Rate	100%	
Expected Annual Hours of Operation	8,760	Hours
Annual Interest Rate	5.5%	
Expected Equipment Life	20	yrs

CONTROL EQUIPMENT COSTS

Capital Costs		
Direct Capital Costs		
Purchased Equipment Total (B)		492,800
Installation Total		660,000
Total Direct Capital Cost, DC		1,152,800
Total Indirect Capital Costs, IC		653,940
Total Capital Investment (TCI) = DC + IC		**1,806,740**
Operating Costs		
Total Annual Direct Operating Costs	Labor, supervision, materials, replacement parts, utilities, etc.	82,450
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	272,926
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**355,376**

Emission Control Cost Calculation (Costs are per Furnace)

Pollutant	**Baseline Emis. T/yr**	**Cont. Emis.**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10		-			-	NA
Total Particulates		-			-	NA
Nitrous Oxides (NOx)	89.0		0.10	31.0	58.0	6,130
Sulfur Dioxide (SO_2)		-			-	NA

Notes & Assumptions

1 Equipment and installation costs from U. S. Steel previous similar project experience
2 Purchased equipment includes low-NOX burners, new combustion air fan, instrumentation, PLC, control valves, controls system, power distribution and equipment to maintain NFPA compliance per code.
3 Installation includes, but is not limited to: installation of upgraded burner ports including boiler and refractory work, natural gas header, and upgrades/repairs to 50-year old infrastructure.
4 Retrofit Costs are intended to address undefined additional costs such as: specific design and space constraints of the facility, structural improvements/repairs that may be necessary, and asbestos/lead paint abatement.
5 Assumed 0.1 and 0.5 hr/shift respectively for operator and maintenance labor
6 Controlled emission factor based on vendor estimated burner performance

U. S. Steel Gary Works
Regional Haze Four-Factor Analysis for NO_X and SO_2 Emission Controls
Appendix C.2 - Table C.2-3: NOx Control - Low NOx Burners (LNB)
Waste Heat Boiler No. 1

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**440,000**
Purchased Equipment Costs			
Instrumentation	0%	Included in purchased equipment cost	0
Sales Taxes	7.0%	of control device cost	30,800
Freight	5%	of control device cost	22,000
Purchased Equipment Total (B)	12%		**492,800**
Installation			
Construction	150%	of purchased equip cost and infrastructure cost	660,000
Installation Total			**660,000**
Total Direct Capital Cost, DC			**1,152,800**
Indirect Capital Costs			
Construction Management and Indirects	15%	Equipment, Infrastructure, and Construction Costs	165,000
Start-up	5%	of purchased equip cost	22,000
Performance test		estimated cost of engineering and performance testing	50,000
Model Studies	NA	of purchased equip cost	NA
Retrofit Costs	30%	of total cost	416,940
Total Indirect Capital Costs, IC			**653,940**
Total Capital Investment (TCI) = DC + IC			**1,806,740**
Site Preparation, as required		Included above	NA
Buildings, as required		Included above	NA
Site Specific - Other		Included above	
Total Site Specific Costs			**0**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**1,806,740**
Total Capital Investment (TCI)			**1,806,740**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	67.53	$/Hr, 0.1 hr/8 hr shift, 8760 hr/yr	7,395
Supervisor	15%	15% of Operator Costs	1,109
Maintenance (2)			
Maintenance Labor	67.53	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr	36,973
Maintenance Materials	100%	of maintenance labor costs	36,973
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**82,450**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	49,470
Administration (2% total capital costs)	2%	of total capital costs (TCI)	36,135
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	18,067
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	18,067
Capital Recovery	8%	for a 20- year equipment life and a 5.5% interest rate	151,187
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**272,926**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**355,376**

U. S. Steel Gary Works
Regional Haze Four-Factor Analysis for NO_X and SO_2 Emission Controls
Appendix C.2 - Table C.2-3: NOx Control - Low NOx Burners (LNB)
Waste Heat Boiler No. 1

Capital Recovery Factors	
Primary Installation	
Interest Rate	5.50%
Equipment Life	20 years
CRF	0.0837

Replacement Parts & Equipment:
N/A

Replacement Parts & Equipment:
N/A

Electrical Use
N/A

Reagent Use & Other Operating Costs
N/A

Operating Cost Calculations — **Annual hours of operation:** **8,760**; **Utilization Rate:** **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	67.53	$/Hr	0.1	hr/8 hr shift	110	7,395	$/Hr, 0.1 hr/8 hr shift, 8760 hr/yr
Supervisor	15%	of Op.			NA	1,109	15% of Operator Costs
Maintenance							
Maint Labor	67.53	$/Hr	0.5	hr/8 hr shift	548	36,973	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	36,973	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.073	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 8760 hr/yr, 100% utilization
Natural Gas	6.15	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8760 hr/yr, 100% utilization
Water	5.13	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8760 hr/yr, 100% utilization

Appendix C.3

Waste Heat Boiler No. 2

U. S. Steel Gary Works
Regional Haze Four-Factor Analysis for NO_X and SO_2 Emission Controls
Appendix C.3 - Table C.3-1: Cost Summary
Waste Heat Boiler No. 2

NO_x Control Cost Summary

Control Technology	Control Eff %	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton
Low NOx Burners (LNB)	65%	30.0	56.0	$1,806,740	$355,376	$6,344

U. S. Steel Gary Works
Regional Haze Four-Factor Analysis for NO_X and SO_2 Emission Controls
Appendix C.3 - Table C.3-2: Summary of Utility, Chemical and Supply Costs
Waste Heat Boiler No. 2

Study Year 2020

Item	2020 Unit Cost	Units	Cost	Year	Data Source
Operating Labor	68	$/hr	60	2016	EPA SCR Control Cost Manual Spreadsheet
Maintenance Labor	68	$/hr			Assumed to be equivalent to operating labor
Other					
Sales Tax	7%			2020	Indiana sales tax rate
Interest Rate	5.50%			2016	EPA SCR Control Cost Manual Spreadsheet
Contingencies	30%	of purchased equip cost (B)			U. S. Steel Estimate
Markup on capital investment (retrofit factor)	0%				EPA Cost Control Cost Manual Chapter 2
Operating Information					
Annual Op. Hrs	8,760	Hours			Assumed
Utilization Rate	100%				Assumed
Design Capacity	226	MMBTU/hr			Design Capacity
Equipment Life	20	yrs			Assumed
Plant Elevation	607	Feet above sea level			Plant elevation
	Baseline Emissions				
Pollutant	**Ton/Year**				
Nitrous Oxides (NOx)	86.0				Estimated 2028 emissions
LNB - NO_x Performance	0.10	lb/MMBtu			Assuming similar performance to reheat furnace LNB.
Baseline NOx performance	0.27	lb/MMBtu			280 lb/MMscf converted to lb/MMBtu assuming 1020 btu/scf for natural gas
Control efficiency	65%				Calculated

U. S. Steel Gary Works
Regional Haze Four-Factor Analysis for NO_X and SO_2 Emission Controls
Appendix C.3 - Table C.3-3: NO_x Control - Low NOx Burners (LNB)
Waste Heat Boiler No. 2

Desgin Capacity	226	MMBtu/hr
Expected Utiliztion Rate	100%	
Expected Annual Hours of Operation	8,760	Hours
Annual Interest Rate	5.5%	
Expected Equipment Life	20	yrs

CONTROL EQUIPMENT COSTS

Capital Costs		
Direct Capital Costs		
Purchased Equipment Total (B)		492,800
Installation Total		660,000
Total Direct Capital Cost, DC		1,152,800
Total Indirect Capital Costs, IC		653,940
Total Capital Investment (TCI) = DC + IC		**1,806,740**
Operating Costs		
Total Annual Direct Operating Costs	Labor, supervision, materials, replacement parts, utilities, etc.	82,450
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	272,926
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**355,376**

Emission Control Cost Calculation (Costs are per Furnace)

Pollutant	**Baseline Emis. T/yr**	**Cont. Emis.**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10		-			-	NA
Total Particulates		-			-	NA
Nitrous Oxides (NOx)	86.0		0.10	30.0	56.0	6,344
Sulfur Dioxide (SO_2)		-			-	NA

Notes & Assumptions

1. Equipment and installation costs from U. S. Steel previous similar project experience
2. Purchased equipment includes low-NOX burners, new combustion air fan, instrumentation, PLC, control valves, controls system, power distribution and equipment to maintain NFPA compliance per code.
3. Installation includes, but is not limited to: installation of upgraded burner ports including boiler and refractory work, natural gas header, and upgrades/repairs to 50-year old infrastructure.
4. Retrofit Costs are intended to address undefined additional costs such as: specific design and space constraints of the facility, structural improvements/repairs that may be necessary, and asbestos/lead paint abatement.
5. Assumed 0.1 and 0.5 hr/shift respectively for operator and maintenance labor
6. Controlled emission factor based on vendor estimated burner performance

U. S. Steel Gary Works
Regional Haze Four-Factor Analysis for NO_X and SO_2 Emission Controls
Appendix C.3 - Table C.3-3: NOx Control - Low NOx Burners (LNB)
Waste Heat Boiler No. 2

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			**440,000**
Purchased Equipment Costs			
Instrumentation	0%	Included in purchased equipment cost	0
Sales Taxes	7.0%	of control device cost	30,800
Freight	5%	of control device cost	22,000
Purchased Equipment Total (B)	12%		**492,800**
Installation			
Construction	150%	of purchased equip cost and infrastructure cost	660,000
Installation Total			**660,000**
Total Direct Capital Cost, DC			**1,152,800**
Indirect Capital Costs			
Construction Management and Indirects	15%	Equipment, Infrastructure, and Construction Costs	165,000
Start-up	5%	of purchased equip cost	22,000
Performance test		estimated cost of engineering and performance testing	50,000
Model Studies	NA	of purchased equip cost	NA
Retrofit Costs	30%	of total cost	416,940
Total Indirect Capital Costs, IC			**653,940**
Total Capital Investment (TCI) = DC + IC			**1,806,740**
Site Preparation, as required		Included above	NA
Buildings, as required		Included above	NA
Site Specific - Other		Included above	
Total Site Specific Costs			**0**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**1,806,740**
Total Capital Investment (TCI)			**1,806,740**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	67.53	$/Hr, 0.1 hr/8 hr shift, 8760 hr/yr	7,395
Supervisor	15%	15% of Operator Costs	1,109
Maintenance (2)			
Maintenance Labor	67.53	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr	36,973
Maintenance Materials	100%	of maintenance labor costs	36,973
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**82,450**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	49,470
Administration (2% total capital costs)	2%	of total capital costs (TCI)	36,135
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	18,067
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	18,067
Capital Recovery	8%	for a 20- year equipment life and a 5.5% interest rate	151,187
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**272,926**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**355,376**

U. S. Steel Gary Works
Regional Haze Four-Factor Analysis for NO_X and SO_2 Emission Controls
Appendix C.3 - Table C.3-3: NOx Control - Low NOx Burners (LNB)
Waste Heat Boiler No. 2

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.50%	
Equipment Life	20	years
CRF	0.0837	

Replacement Parts & Equipment:
N/A

Replacement Parts & Equipment:
N/A

Electrical Use
N/A

Reagent Use & Other Operating Costs
N/A

Operating Cost Calculations — **Annual hours of operation:** **8,760**; **Utilization Rate:** **100%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Operating Labor							
Op Labor	67.53	$/Hr	0.1	hr/8 hr shift	110	7,395	$/Hr, 0.1 hr/8 hr shift, 8760 hr/yr
Supervisor	15%	of Op.			NA	1,109	15% of Operator Costs
Maintenance							
Maint Labor	67.53	$/Hr	0.5	hr/8 hr shift	548	36,973	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	36,973	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.073	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 8760 hr/yr, 100% utilization
Natural Gas	6.15	$/kscf	0	scfm	0	0	$/kscf, 0 scfm, 8760 hr/yr, 100% utilization
Water	5.13	$/kgal	0.0	gpm	0	0	$/kgal, 0 gpm, 8760 hr/yr, 100% utilization

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Appendix F

Cokenergy Four-Factor Analysis Submittal

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Cokenergy, LLC
3210 Watling Street MC 2-991
East Chicago, IN 46312

September 30, 2020 Via Electronic Mail

Indiana Department of Environmental Management
Office of Air Quality
100 N. Senate Avenue
Mail Code 61-53, IGCN 1003
Indianapolis, IN 46204 - 2251

Subject: Cokenergy, LLC Regional Haze Four-Factor Analysis Report

Dear Jean:

Attached please find Cokenergy's Regional Haze Four-Factor Analysis Report requested by your office on June 18, 2020. Based on the information presented in this report, Cokenergy's position is that a Four-Factor Analysis should not be required. Notwithstanding and without conceding the applicability of a Regional Haze Four-Factor Analysis, Cokenergy is providing this report to respond to IDEM's request.

Our report also includes a significant discussion on the capital improvements and optimization work Cokenergy has completed over the past several years on our system which support our position that no additional SO2 control measures are necessary for IDEM to meet the Regional Haze Program requirements.

If you have any questions, please contact me at lford@primaryenergy.com or (219) 397-4626.

Sincerely,

Luke E. Ford
Director EH&S
Primary Energy

File: X:\\ 660

REGIONAL HAZE FOUR-FACTOR ANALYSIS

Cokenergy > East Chicago, Indiana

Prepared By:

Cokenergy, LLC
3210 Watling St, MC 2-991
East Chicago, Indiana 46312

TRINITY CONSULTANTS
1717 Dixie Hwy Suite 900
Covington, Kentucky 41011

September 2020

Project 201801.0091

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LIST OF FIGURES

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ACRONYM LIST

ArcelorMittal Indiana Harbor Works	Arcelor-IH
Area of Influence	AoI
Calcium	Ca
Calcium Hydroxide	$Ca(OH)_2$
Clean Air Act	CAA
Comprehensive Air Quality Model with Extensions	CAMx
Consent Decree	CD
Continuous Emissions Monitoring System	CEMS
Dry Sorbent Injection	DSI
Electric Generating Utilities	EGU
Emission Tracking System	ETS
Flue Gas Desulfurization	FGD
Heat Recovery Steam Generator	HRSG
Indiana Department of Environmental Management	IDEM
Indiana Harbor Coke Company	IHCC
Induced Draft	ID
Kilometer	km
Kentucky Division for Air Quality	KDAQ
Key Performance Indicators	KPI
Lake Michigan Air Directors Consortium	LADCO
New Source Review	NSR
Particulate Matter	PM
Particulate Matter Source Apportionment Technology	PSAT
Prevention of Significant Deterioration	PSD
Preventive Maintenance and Operation	PMO
Regional Haze	RH
Regional Planning Organization	RPO
Southeastern Air Pollution Control Agencies	SESARM
Spray Dryer Absorber	SDA
State Implementation Plan	SIP
Steam Turbine Generator	STG
Sulfur Dioxide	SO_2
Tons per year	tpy
Uniform Rate of Progress	URP

Visibility Improvement State and Tribal Association	VISTAS
US Environmental Protection Agency	EPA

1. EXECUTIVE SUMMARY

This report was prepared on behalf of Cokenergy, LLC (Cokenergy) in response to the June 2020 Indiana Department of Environmental Management (IDEM) Regional Haze State Implementation Plan Second Planning Period Request for Four-Factor Analysis request letter. IDEM requested that Cokenergy prepare a Four-Factor Analysis per Section 169a(g)(1) of the Clean Air Act (CAA) to support IDEM's development of a revised Regional Haze State Implementation Plan (SIP) for the second planning period, 2018 to 2028. The second planning period SIP is due for submission to Region 5 of the US Environmental Protection Agency (EPA) by July 31, 2021.[1]

As detailed in IDEM's Four-Factor Analysis request to Cokenergy, this report provides information related to the sulfur dioxide (SO_2) emissions from the lime spray dryer flue gas desulfurization (FGD) unit Cokenergy operates at its Indiana Harbor heat recovery facility (Facility). In addition, this report discusses the nominal (if any) impact Cokenergy's SO_2 emissions have on the relevant Class I area[2], Mammoth Cave National Park, for which this Regional Haze (RH), analysis is being conducted. This report also discusses the significant SO_2 reductions Cokenergy recently made to optimize its FGD system including the extensive capital costs related to that work, and other important information that Cokenergy suggests being considered as part of IDEM's second planning period SIP report to Region 5. Indeed, Cokenergy's FGD optimization measures have reduced the SO_2 emissions by more than 15%. Based on these factors and the information presented in this report, Cokenergy's view is that no additional SO_2 reductions from the Facility should be required to meet RH requirements.

Cokenergy operates as a contractor[3] at the ArcelorMittal Indiana Harbor Works, Arcelor-IH, facility in East Chicago, Indiana. The Facility is an energy facility that includes the integrated combined heat and power project using waste heat recovered from non-recovery coke batteries[4] owned and operated by Indiana Harbor Coke Company (IHCC). The Facility provides electricity and industrial process steam to the ArcelorMittal integrated steel mill operation. A schematic of the Cokenergy Facility showing its relationship with Arcelor-IH and IHCC is shown in Figure 1-1.

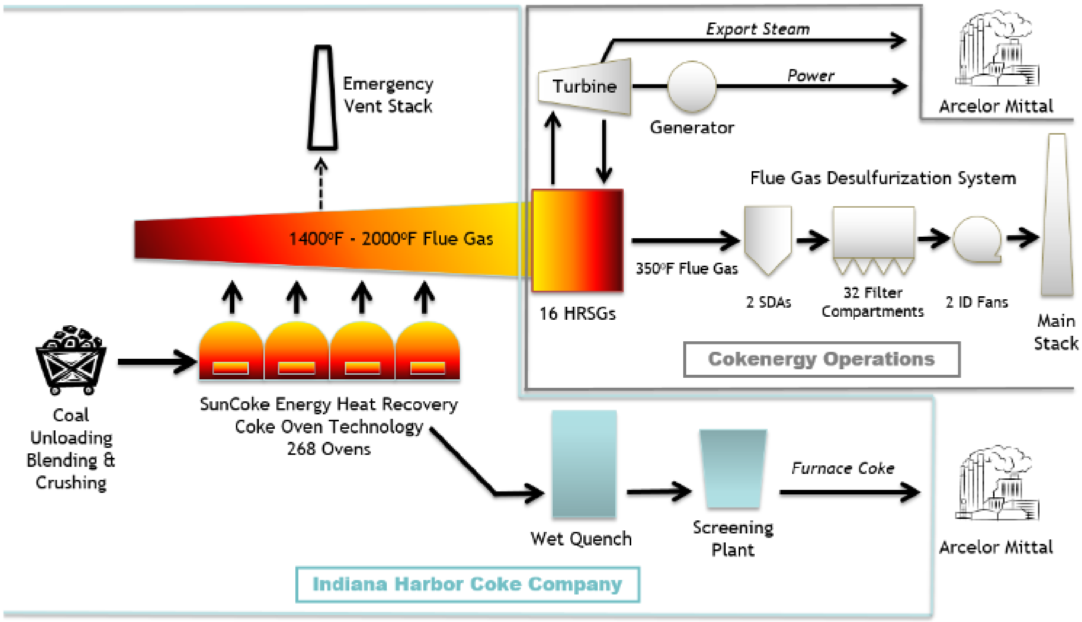
[1] 40 CFR 51.308(f)

[2] Class I areas are designated by the CAA which gave special air quality and visibility protection to national parks larger than 6,000 acres and national wilderness areas larger than 5,000 acres that were in existence when the CAA was amended in 1977.

[3] Cokenergy leases the property necessary for its operations from Arcelor-IH.

[4] Cokenergy does not combust any fuel within its physical boundaries. The design of the non-recovery coke batteries operated by IHCC completely exhausts all heating value from the coal in the coke oven.

Figure 1-1. Schematic of Cokenergy, IHCC, and Arcelor-IH Process Flow



IDEM indicated during a webinar specifically held for Indiana facilities, that IDEM would request Cokenergy to conduct a Four-Factor Analysis. IDEM's request specified that Cokenergy conduct this analysis for SO_2 emissions from the FGD unit operated at the Facility. IDEM's four-factor selection rankings identified iron/steel mills, cement manufacturing kilns, and two other non-electric generating utilities (EGUs) industrial sources as the source categories for analysis of control measures during this second RH implementation period.

IDEM based inclusion of sources in this second implementation period of RH planning on a ratio of 2018 actual annual emissions of visibility-affecting pollutants (determined to be NO_X and SO_2 for Indiana), known as "Q" in tons per year (tpy), and distance to Class I area, known as "d" in kilometers (km). IDEM has selected the cautious ratio criteria of "Q/d > 5.0" to identify the facilities for which four-factor analyses were requested. Based on this screening approach, IDEM calculated the "Q/d" ratio to be 10.695[5] for Cokenergy (i.e., the SO_2 emissions from FGD unit), which led to IDEM's request that Cokenergy develop a Four-Factor Analysis.

However, as detailed in Section 2-1, a more comprehensive analysis which included air modeling was conducted by another state agency and a Regional Haze Planning Organization (RPO), that indicated Cokenergy has no visibility impact on Mammoth Cave, the Class I area nearest the Facility.

In 2014 Cokenergy contracted with an engineering firm to conduct a study to evaluate and optimize the existing FGD system that controls the SO_2 emissions from the process. The coke oven flue gas enters the heat recovery steam generators (HRSGs) operated by Cokenergy that produce process steam and electricity for the Arcelor-IH facility from heat recovered from the coke ovens. The flue gas is then directed to the FGD system, which consists of two (2) spray dryer absorbers (SDAs) where the flue gas mixes with sorbent to

[5] Actual 2018 sitewide SO_2 emissions of 5,398 tpy with a distance of 505 km to Mammoth Cave NP (5,398, Q / 505 d = 10.695).

remove SO_2 then the flue gas goes through two (2) pulse jet, fabric filter baghouses to remove particulate. The recommended strategy to optimize the existing FGD was to operate the dual SDAs in parallel rather than one SDA being a backup/standby unit. After the 2014 engineering study was completed, Cokenergy refined the design to operate both SDAs in parallel in a second engineering study completed in 2015.

This report provides a comprehensive review of the already completed FGD improvements resulting in SO_2 reductions at Cokenergy. These already-realized SO_2 reductions from the optimization of the existing FGD system are well documented for incorporation of the SO_2 reductions into a recent Consent Decree entered in late 2018 (the CD) and/or IDEM's SIP validating that Cokenergy's FGD is achieving higher SO_2 removal than prior to the CD.[6] IDEM has incorporated portions of the CD in Cokenergy's Title V operating permit, T089-41033-00383, Section D.1.2 Lake County Sulfur Dioxide Emission Limitations [326 IAC 7-4.1-7] [Consent Decree, Civil Action No. 18cv-35] [326 IAC 2-7-10.5(b)(2)].

Importantly, Cokenergy invested approximately $9.3 million between 2014 and 2018 to optimize the FGD system as well as $32 million to retube the HRSGs between 2010 and 2015. Cokenergy has continued to monitor performance and engage in practices to demonstrate good operating, engineering, and air pollution control practice for minimizing air emissions and ensuring continual compliance with all Title V operating permit and the CD requirements.[7]

In addition to information presented herein, the following specific technical and economic information, where applicable, is provided in this report for each emissions reduction option considered, in accordance with instructions in the Four-Factor Analysis request provided by IDEM in mid-June 2020 and supports Cokenergy's position that no additional actions are required by Cokenergy to address the impact of RH on Mammoth Cave:

- Identification of technically feasible options (not included by IDEM, but appropriate initial step to eliminate and document options that are not technically feasible)
- Costs of implementation[8] (Statutory Factor 1)
- Time necessary for implementation[8] (Statutory Factor 2)
- Energy and non-air quality environmental impacts[8] (Statutory Factor 3)
- Remaining useful life[8] (Statutory Factor 4)

Based on the extensive capital, employee and consultant hours already invested in reducing SO_2 emissions from Cokenergy's FGD, RH program guidance, physical limitations, and other data and factors detailed in this report, no control devices were deemed technically feasible to evaluate through the four statutory factors. This position is also supported by the minimal impact that Cokenergy's emissions have on Mammoth Cave.

[6] Cokenergy has complied with the required milestones of the CD process. All documentation is publicly available on Indiana Harbor Coke/Cokenergy Consent Decree website.

[7] The CD required Cokenergy to develop and submit a preventive maintenance and operation plan (PMO Plan) per IV. Compliance Requirements D. 23. a. Cokenergy submitted a PMO on December 13, 2018.

[8] These are the four factors that must be included in evaluating emission reduction measures necessary to make reasonable progress determinations. See 40 CFR 51.308(f)(2)(i). Technical feasibility, control effectiveness and emissions reductions information are required to assess the cost of implementation.

2. REGIONAL HAZE BACKGROUND

2.1 Regional Haze Program

Pursuant to 40 CFR 51.308(d), each state must address RH in each mandatory Class I Federal area located within or outside of the state if affected by interstate emissions. States must establish reasonable progress goals which provide for an improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period. The RH program is within the second planning period (2018 to 2028).

2.2 IDEM's Request to Cokenergy

IDEM sent Cokenergy a Four-Factor Request Letter, via email, on June 18, 2020 which included the list of emission units to be included in the Four-Factor Analysis. IDEM's request of Cokenergy included SO_2 emissions from Stack 201, the exhaust stack of the FGD system.

IDEM described their selection methodology to request Four-Factor Analyses for facilities in Indiana during the June 3, 2020 webinar. To summarize the information presented, IDEM selected steel mills[9], cement kilns[10], and non-EGU sources with a "Q/d" greater than 5.0 to complete or request completion of a Four-Factor Analysis. IDEM indicated the "Q/d" approach was chosen to include a reasonable number of sources to be evaluated and for consistency with other Lake Michigan Air Directors Consortium (LADCO) states. LACDO is a RPO and includes Indiana, Illinois, Ohio, Wisconsin, and Michigan.

The "Q/d" selection criterion is the least complicated technique offered in the guidance memorandum by EPA on RH SIP for the Second Implementation Period.[11] The additional selection criteria suggested by EPA in the guidance memo are, ranked in order of least to most complicated:

- Emissions divided by distance ("Q/d") – Ratios SO_2 and NO_X emissions with distance to Class I areas.
- Trajectory analyses – Examines the wind direction on individual days.
- Residence time analyses – A trajectory-based analysis technique that combine emissions, ambient particulate data, and trajectory information.
- Photochemical modeling (zero-out and/or source apportionment) – The only air modeling technique suggested by EPA. Photochemical modeling quantifies source or source sector visibility impacts.

Although the "Q/d" selection technique is easy to implement, it does not include as much information as the three (3) more complex selection techniques suggested by EPA. The more sophisticated techniques account for detailed information on particulate (PM) and PM species impacts but are more resource intensive. EPA allowed each state to choose their own Four-Factor Analysis selection techniques and did allow states to use other reasonable techniques as appropriate.

IDEM's "Q/d >5.0" selection criterion does not account for the data analyzed (i.e., photochemical modeling) and summarized by RPOs. Based on the RPO modeling results conducted by the Visibility Improvement

[9] Cokenergy operates as a contractor within the Arcelor-IH site, an integrated steel mill, but is not in itself a steel mill.

[10] IDEM requested Four-Factor Analyses for the two cement facilities in Indiana with a "Q/d > 5.0" (Lehigh Cement Company and Lone Star Industries Inc).

[11] EPA memorandum- Guidance on Regional Haze State Implementation Plans for Second Implementation Period, August 2019.

State and Tribal Association of the Southeast (VISTAS), Cokenergy's SO_2 emissions do not have a sulfate or nitrate impact on Mammoth Cave greater than or equal to 1.00 percent of the total sulfate plus nitrate point source visibility impairment on the twenty (20) percent most impaired days. This criterion is used to include or exclude, in Cokenergy's case, emissions from a point source as within the Area of Influence (AoI) of a Class I area.

2.3 VISTAS Class I Impacts Outside Region

Cokenergy reviewed publicly available guidance documents from the VISTAS to investigate any potential visibility impact Cokenergy may have on Class I areas. As noted previously, Mammoth Cave is in Kentucky. The VISTAS, a subcommittee of the Southeastern Air Pollution Control Agencies (SESARM), conducted technical analyses to help states identify sources that significantly impact visibility impairment for Class I areas within and outside of the VISTAS region (i.e., VA, WV, NC, SC, GA, FL, AL, TN, MI, KY, GA). VISTAS conducted an AoI analysis to identify sources to "tag" for PM Source Apportionment Technology (PSAT) modeling which was implemented with the Comprehensive Air Quality Model with Extensions (CAMx) to identify emissions sources which strongly contribute to RH.[12] VISTAS identified three (3) impactful sources[13] in Indiana as a result of this analysis that did not include Cokenergy.[14] Therefore, the VISTAS modeling efforts support Cokenergy's position that the Facility was not a source shown to have a significant sulfate or nitrate impact on a Class I area.

In addition, VISTAS updated 2028 CAMx modeling with actual observations through 2018 and revised future projections based on reasonable progress.[15] As indicated in Figure 2-1, Mammoth Cave is below the target uniform rate of progress (URP) glidepath line. Therefore, additional emission reductions beyond those already planned are not required to meet the 2028 uniform progress goal for visibility at Mammoth Cave.

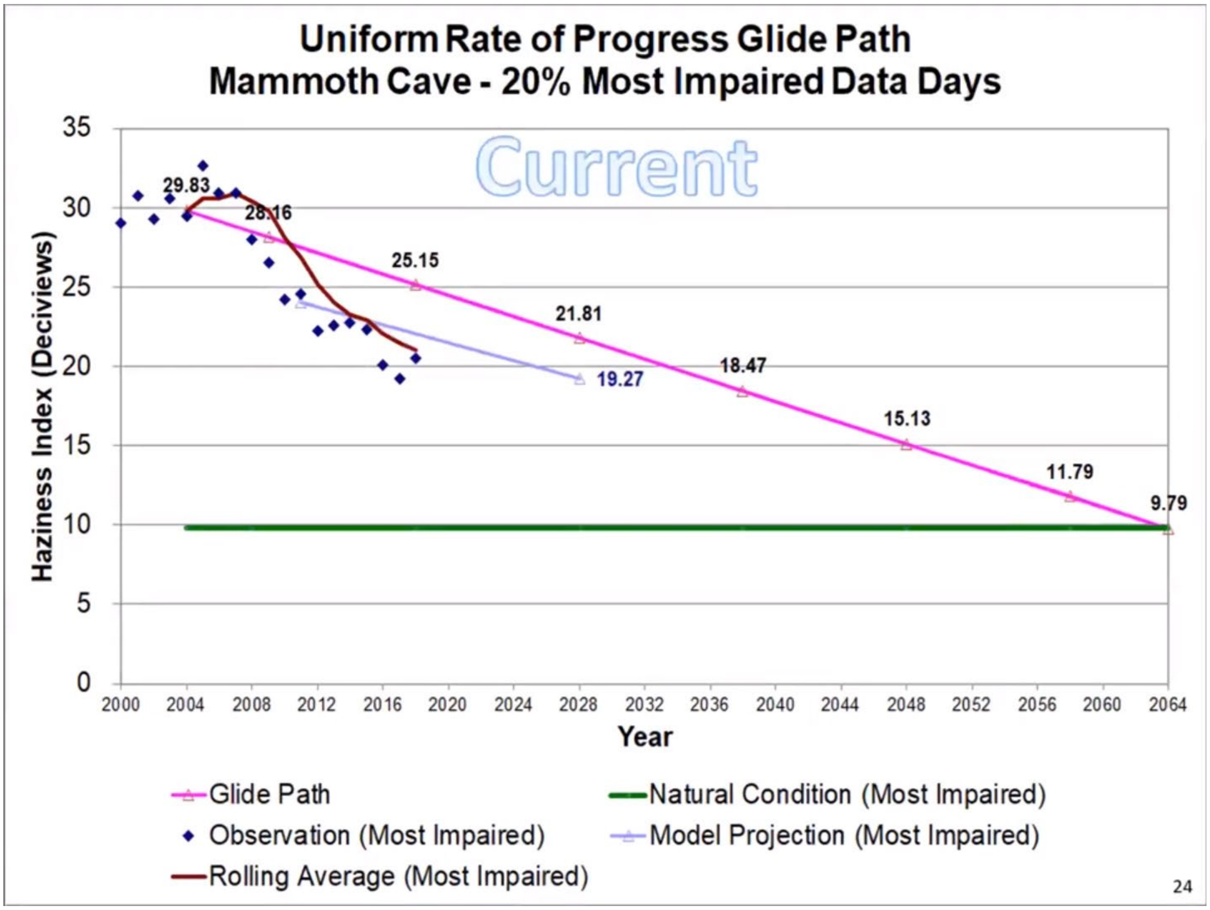
[12] Sources shown to have a sulfate or nitrate impact on one or more Class I areas greater than or equal to 1.00% of the total sulfate plus nitrate point source visibility impairment on the 20% most impaired days for each Class I area

[13] VISTAS identified Indianapolis Power & Light Petersburg (18125-73624111), Gibson (18051-7363111), and Indiana Michigan Power DBA AEP Rockport (18147-9017211) as the Indiana sources shown to have a sulfate or nitrate impact on one or more Class I areas greater than or equal to 1.00 percent of total sulfate plus nitrate point source visibility impairment on the 20 percent most impaired days for each Class I area.

[14] VISTAS Letter- Request for Regional Haze Reasonable Progress Analyses for Indiana Sources Impacting VISTAS Class I Areas, June 2020.

[15] VISTAS presentation- Regional Haze Project Update- EPA, FLM, RPO Briefing https://youtu.be/FN83NmV0JWQ , August 2020.

Figure 2-1. VISTAS Haziness Index Modeling Results – Mammoth Cave Class I Area

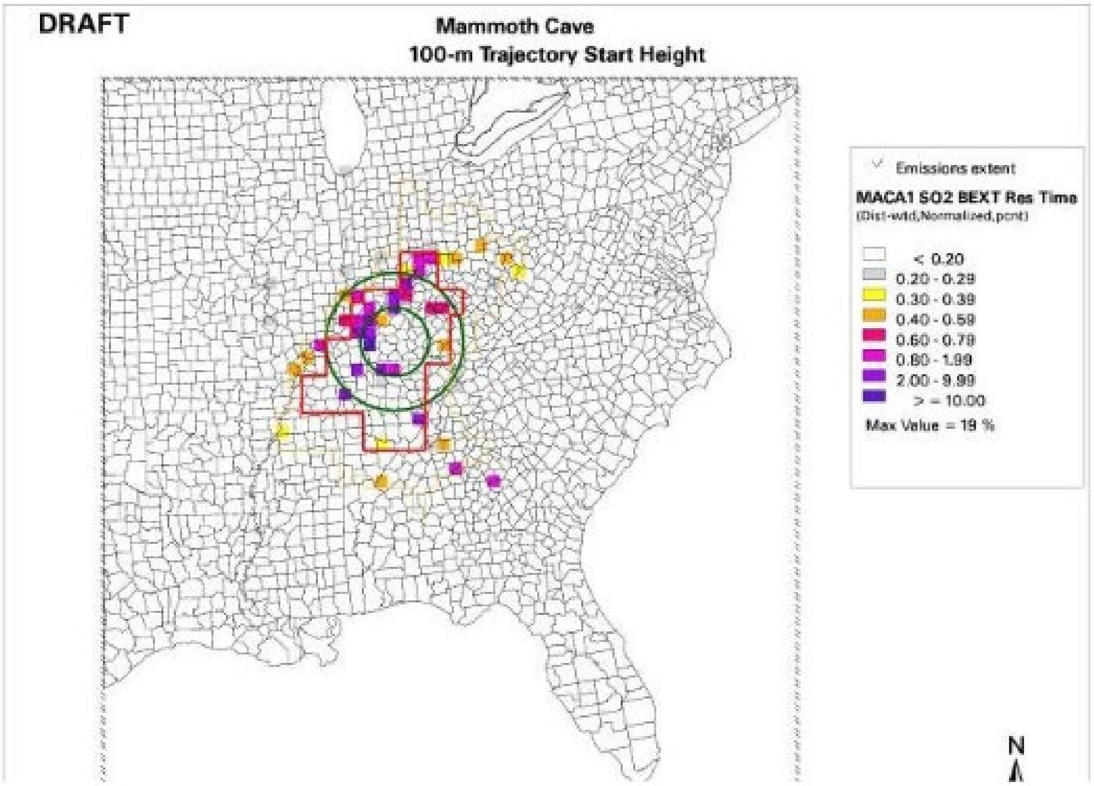


2.4 Kentucky Division of Air Quality-Area of Influence for Mammoth Cave

Kentucky Energy and Enviroment Cabinet-Kentucky Division for Air Quality (KDAQ) released a SIP Revision: Regional Haze 5-Year Periodic Report 2008-2013[16] for Kentucky's Class I Federal Area. The closest Class I area to Cokenergy is Mammoth Cave located in Kentucky. Mammoth Cave is the only Class I area IDEM indicated Cokenergy address in this Four-Factor Analysis. Figure 2-2 illustrates the sulfate extinction-weighted residence time plot for Mammoth Cave. Cokenergy is well outside the AoI of SO_2 for Mammoth Cave with the residence time being less than 0.20 percent.

[16] KDAQ SIP Revision for Kentucky's Regional Haze Periodic Report, September 2014.

Figure 2-2. SO_2 Area of Influence for Mammoth Cave, KY



Green circles indicate 100-km and 200-km radii from Class I area.
Red line perimeter indicate Area of Influence with Residence Time $\geq$ 10%.
Orange line perimeter indicate Area of Influence with Residence Time $\geq$ 5%.

2.5 Cokenergy's Summary of Facility's Regional Haze Impact

The data presented and detailed in this report, from VISTAS and KDAQ support Cokenergy's view that SO_2 emissions from Cokenergy's Facility do not impact Mammoth Cave. Therefore, Cokenergy's position is that a Four-Factor Analysis should not be required for the facility. Notwithstanding and without conceding the applicability of RH Four Factor Analysis requirements to the Facility, Cokenergy is responding to IDEM's request by submitting this four-factor report, although no current data indicates the Facility's emissions impact Class I visibility.

In addition, Cokenergy has undergone numerous studies and projects in the last several years, additional details in Section 3, that reduced SO_2 emissions through optimization of the exisitng FGD system.

3. COKENERGY FACILITY HISTORY

3.1 Facility Description

The Arcelor-IH facility[17] was established as an integrated steel mill more than 100 years ago. In 1998, Primary Energy (Primary) began operating Cokenergy within the Arcelor-IH facility. The Cokenergy facility is a first-of-a-kind combined heat and power system that uses the waste heat in the flue gas from IHCC's metallurgical coke facility to produce steam and power for the Arcelor-IH facility.

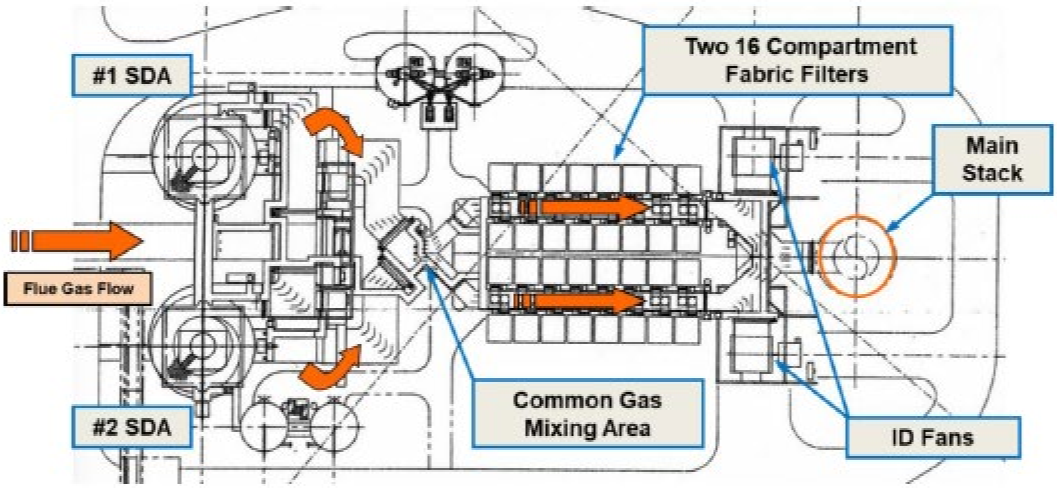
Cokenergy's sixteen HRSGs, arranged four per oven battery, receive and recover heat from the coke oven flue gas, producing power-grade steam and cooling the gas in the process. The superheated steam is used to generate electricity in an industrial condensing/extraction steam turbine. With the steam and power generated in this process, Cokenergy supplies electricity as well as high-pressure process steam to Arcelor-IH. After the flue gas passes through the HRSGs, Cokenergy's FGD system environmentally treats the cooled flue gas to remove SO_2 and particulate emissions. The inter-relationship among Cokenergy, Arcelor-IH, and IHCC is graphically shown in Figure 1-1.

Figure 3-1 provides a basic schematic of Cokenergy's FGD:

- Sixteen (16) HRSGs, four (4) per coke oven battery. The HRSGs recover heat from the coke oven flue gas.
- Flue gas ductwork to manifold the flue gas from the HRSGs to Cokenergy's FGD system.
- Two (2) SDA. The mixing of flue gas with sorbent material to environmentally treat, or remove, SO_2 from the flue gas.
- Two (2) individual sixteen (16) compartment pulse jet, fabric filter baghouse, which removes particulate emissions from the flue gas.
- Two (2) induced draft (ID) fans, which pull draft through the entire flue gas system from the coke ovens to the ID fans.
- One (1) extraction/condensing steam turbine generator (STG). The STG accepts the steam generated by the HRSGs and includes a six (6)-cell cooling tower, boiler feedwater heater, two (2) deaerators.

[17] The current Arcelor-IH facility has had various owners since beginning operation, ArcelorMittal USA LLC took ownership in 2002.

Figure 3-1. Schematic of Cokenergy's FGD



Particulate emissions are not included in IDEM's Four-Factor Analysis request; therefore, this report exclusively provides information related to the SO_2 effective and reasonable control measures considering the costs of compliance for Cokenergy's FGD system.

3.2 Review of FGD Optimization Projects and Milestones

The FGD system at Cokenergy became fully operational in 1998 with the original system design being similar to FGDs for coal-fired EGUs. The original FGD system, as installed, did contain the same equipment as listed in Section 3.1 where the original design called for operating one SDA train (SDA, SDA bypass duct, and ID fan) and the other SDA train was run in standby mode. Beginning in 2010 Cokenergy began the process of investigating potential means to increase the FGD system's SO_2 control rates to reduce emissions and ensure the reliability of the FGD system.

Cokenergy began engineering studies in 2012 to optimize the FGD system. Prior to beginning the engineering studies, the re-tubing of the sixteen (16) HRSGs had begun. The retubing projects in themselves significantly reduced SO_2 emissions through the reduction in bypass venting. The notable milestones of the Facility's FGD optimization[18] are:

- 2010 to 2015 – Retubed all sixteen (16) HRSGs
- 2012 – Consultant identified a series of FGD improvement options
- 2014 – First engineering study began
  - Evaluate and understand original FGD design and capabilities
  - Determine any intrinsic design issues
  - Develop and evaluate SDA models
  - Identify possible FGD enhancements for existing FGD system
- 2014 to 2015 – Engineering feasibility study
  - Refine and select FGD optimization projects
  - Improve reliability and enhancement of FGD equipment

[18] These steps did include reducing PM as well as SO_2, which is the pollutant of focus for Cokenergy's Four-Factor Analysis.

- 2015 to 2016 – Implement FGD upgrade projects
- 2016 – Employed the approach temperature optimization program
- January 2018 – Consent Decree lodged
- Continuing optimization of FGD system through performance monitoring program

Since the beginning of the FGD optimization project in 2012 Cokenergy has invested tremendous resources to achieve the overarching goal of reducing SO_2 emissions from the FGD system. These projects have reduced the SO_2 emissions from the FGD by **more than 15 percent (%)**. A summary of the actual SO_2 emissions and percent reduction of SO_2 prior to and after the extensive projects completed by Cokenergy are detailed in Table 3-1.

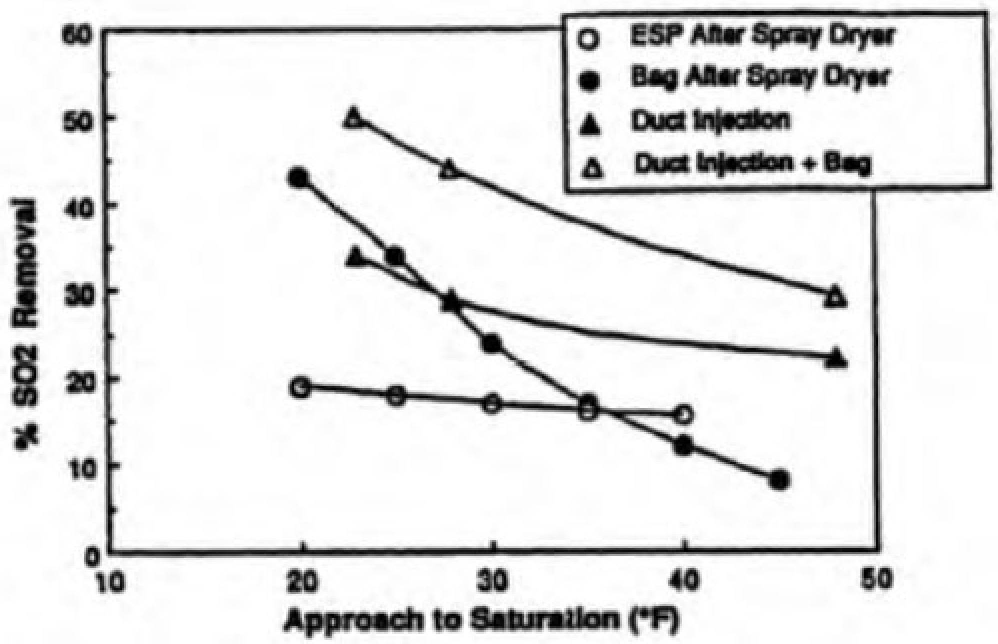
3.2.1 Key Factors to Enhancement of FGD System

The following factors were important considerations to the FGD optimization projects and were studied in detail during the engineering studies completed by Cokenergy. Each factor that was considered is described below, and the meaningful impact to SO_2 is summarized as well.

- HRSG Retubing
  - Completed retubing of all 16 of the HRSGs that allowed for a reduction in the amount of over-scrubbing required by the FGD, reduced the pressure drop by using finned tubes, and reduced venting from the emergency bypass vent stacks.
- Reduce Flue Gas Volume
  - Replaced dampers and reduced air in-leakage rates to lower the high flue gas volumetric flow rate at the inlet of the SDA. The flue gas flow rates to the SDA were too high and resulted in a reduced capture efficiency of the SDA.
  - With the reduction of flue gas flow into the SDA increased overall performance by allowing the SDA to capture more gas volume.
- Increase Gas Temperature
  - Increased flue gas temperature into the SDA was achieved by reducing the false air (i.e. in-leakage from the ambient environment that is not flue gas) entering the SDA.
  - A higher flue gas temperature allows for a higher water/lime slurry injection rate; therefore, increasing the SO_2 capture and control effectiveness. Controlling the water/slurry lime slurry injection rate as the desired ratio allowed for more consistent SDA performance.
- Increase Calcium to Sulfur Ratio
  - An increase in the calcium (Ca) injection ratio was achieved by reducing the flue gas volume.
  - SO_2 removal is directly associated with a higher Ca/sulfur ratio into the SDA.
- Increase Residence Time
  - A reduction in flue gas volume allowed for a longer residence time, or amount of time the flue gas is inside the SDA, for SO_2 absorption into the evaporating slurry droplets. The absorption of SO_2 into slurry droplets is the mechanism in which SO_2 is captured or removed from flue gas. The captured SO_2 droplets exit the SDA as solids.
  - The increased residence time has a direct influence on higher SO_2 capture during spray droplet evaporation.
- Increase SO_2 Removal with Approach to Dew Point
  - Cokenergy installed instrumentation and controls to improve the removal efficiency of the SDA by controlling the approach temperature to allow for optimal scrubbing.

- This theory is defined as approach to dew point or saturation temperature. The closer the SDA operates to the saturation temperature, the higher the final SO_2 removal as shown in Figure 3-2.[19]
- SO_2 removal rate is influenced by the relationship between the final flue gas temperatures and moisture content.

Figure 3-2. SO_2 Removal Efficiency Related to "Approach to Dew Point"



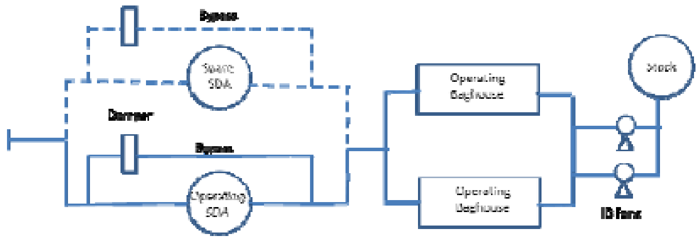
3.2.2 Enhanced FGD Scenarios Evaluated in 2014 Study

The following four (4) scenarios described below were studied in detail by Burns and Roe Enterprises, Inc. and summarized in a report from June 9, 2014. Additionally, a stand-alone additional FGD system that contains one SDA was also evaluated as a means of assuring 100% availability but was deemed inappropriate due to the high estimated capital cost relative to any emissions reductions, increased maintenance, expected chemical usage, and difficulties related to positioning and available footprint.

► One (1) SDA in Operation Scenario - Figure 3-3
  - This was the current configuration at the time of the study such that the second SDA was operating as a backup or in standby mode. In this study, it was concluded this option means approximately 38% of the flue gas needs to be bypassed as to not exceed the design retention time of ten (10) seconds. This configuration requires an SO_2 removal efficiency of 80.3% to achieve the current Title V permit limit of 1,656 lb/hr.

[19] "Dry Scrubbing Technologies for Flue Gas Desulfurization," Ohio Coal Research Consortium, 1998.

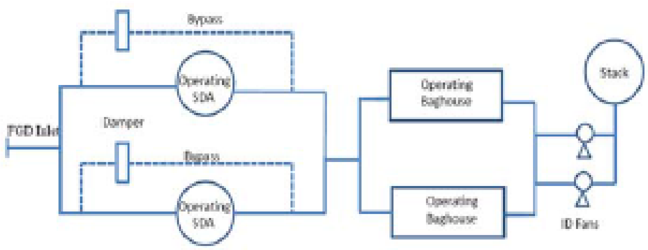
Figure 3-3. One (1) SDA in Operation Scenario from 2014 Study



One (1) SDA in Operation

- Two (2) SDAs Operating in Parallel Scenario - Figure 3-4
  - This was the overall optimal option found during the study. This option can accommodate the full flue gas volume with a residence time of 12.4 seconds, which was longer than the first scenario allowing for longer reaction time to increase SO_2 removal rates.

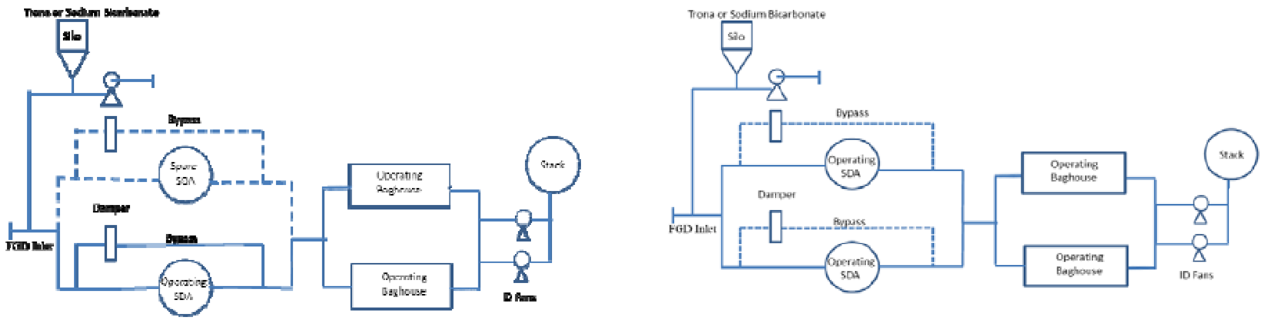
Figure 3-4. Two (2) SDAs in Operation Scenario from 2014 Study



Two (2) SDA's in Operation

- Dry Sorbent Injection (DSI) with Trona with One (1) or Two (2) SDAs in Operation Scenarios - Figure 3-5
  - The option of adding a DSI upstream of both the single SDA and dual SDA configurations was considered. The SO_2 removal capability of the FGD system with DSI of Trona is significantly enhanced for single SDA operation and marginally increased during operation with two SDA's. However, the added capital cost and annual operating cost relative to any emissions reductions, and the environmental concerns of sodium in the by-product, significantly detract from the overall benefits of DSI.

Figure 3-5. DSI with Trona Scenarios from 2014 Study



DSI Stand Alone System with Trona
One (1) SDA in Operation

DSI with Trona
Two (2) SDA's in Operation

3.2.3 Phase 2 Study Highlights

The Phase 2 study by POWER Burns and Roe summarized in the May 25, 2015, report focused on determining the best means of revitalizing the existing FGD system to accommodate current and future operating conditions which included the following:

- Implementation of dual SDA operation
- Procurement of fourth atomizer
- Replace the original SDA upstream and downstream isolation dampers
- Consider implementation of upstream gas conditioning system
- Optimization of baghouse cleaning
- Optimization of SDA exit temperature
- Upgrades to redundant atomizer chiller system
- Continue to address air infiltration throughout the oven/HRSG/FGD system

3.2.4 Comparison of 2014 and 2020 Emissions to Show Improvements

The combined SO_2 limit in Cokenergy's and IHCC's Title V permits is 1,656 lb/hr. The combined emission rate for both plants is determined by summing SO_2 emissions from the IHCC emergency bypass vent stacks with the emissions from Cokenergy Stack 201 using the emission tracking system (ETS) in coordination with the Cokenergy Continuous Emissions Monitoring System (CEMS). ETS uses coke production data, HRSG steam production, vent lid status, and coal analytical data to calculate the potential SO_2 emissions from venting using a material balance. Cokenergy provides the actual SO_2 data from the stack CEMS.

Table 3-1 provides a summary of this ETS output with additional calculations to demonstrate the impact of the FGD enhancements made in recent years on improved SO_2 removal efficiency. A six (6) month period from November 2014 to April 2015 was selected to represent the pre-FGD enhancements timeframe. The most recent semiannual period, January 2020 through June 2020, was used to demonstrate the post-FGD enhancement timeframe.

The ETS input variables of stack SO_2 emissions, bypass SO_2 emissions, total SO_2 emissions, coal charge, coal sulfur content, coke production, and sulfur content of the finished coke were used to estimate SO_2 input and output to and from the FGD system which estimates the FGD SO_2 control efficiency.

As demonstrated in Table 3-1, the semiannual average control efficiency pre-FGD enhancement was approximately 43% whereas the semiannual average control efficiency post-FGD enhancement was approximately 61%.

$$Raw\ SO_2\ Input\ to\ FGD = [Coal\ Charge\ (tons)\ x\ Coal\ Sulfur\ Content\ (\%)] -$$

$$[Coke\ Production\ (tons)\ x\ Coke\ Sulfur\ Content\ (\%)]\ x\ \frac{2000\ lbs}{ton}\ x\ \frac{64\ \frac{lb}{lbmol} SO_2}{32\ \frac{lb}{lbmol}\ S}\ x\ \frac{1\ day}{24\ hours}$$

$$SO_2\ \ Input\ to\ the\ SDAs = Stack\ SO_2\ \ emissions - Raw\ SO_2\ \ Input\ to\ FGD$$

$$SDA\ SO_2\ Control\ Efficiency = 100\ x\ \frac{SO_2\ \ Input\ to\ SDAs - Stack\ SO_2}{Raw\ SO_2\ \ Input\ to\ FGD}$$

Table 3-1. Summary of Cokenergy SO_2 Emissions Pre and Post FGD Enhancements [a]

		Monthly Average Stack SO2 Emissions (lb/hr)	Monthly Average Bypass Stack SO2 Emissions (lb/hr)	Monthly Average Total SO2 Emissions (lb/hr)	Monthly Average Coal Charge (ton/day)	Monthly Average Coal Sulfur Content	Monthly Average Coke Production (ton/day)	Monthly Average Coke Sulfur Content (%)	Monthly Average SO2 Input to FGD (lb/hr)	Monthly Average SO2 Input to SDA (lb/hr)	Monthly Average SDA SO2 Control Efficiency (%)	Semiannual Average SDA SO2 Control Efficiency (%)
Pre-FGD Enhancement Timeframe	Nov-14	1,413	152	1,565	4,351	0.84	2,872	0.61	3,172	3,020	49%	43%
	Dec-14	1,529	21	1,551	4,266	0.81	2,815	0.60	2,943	2,922	46%	
	Jan-15	1,505	35	1,540	3,670	0.81	2,454	0.60	2,501	2,466	35%	
	Feb-15	1,540	15	1,555	3,707	0.80	2,443	0.60	2,499	2,484	37%	
	Mar-15	1,414	115	1,530	3,814	0.79	2,528	0.59	2,535	2,420	42%	
	Apr-15	1,399	179	1,578	4,284	0.81	2,753	0.61	2,985	2,805	46%	
Post-FGD Enhancement Timeframe	Jan-20	1,175	181	1,356	5,074	0.93	3,325	0.71	3,952	3,771	64%	61%
	Feb-20	1,175	173	1,347	4,957	0.89	3,084	0.73	3,569	3,396	60%	
	Apr-20	1,312	72	1,384	4,998	0.89	3,315	0.66	3,736	3,664	63%	
	May-20	1,364	5	1,369	4,965	0.90	3,302	0.68	3,674	3,669	60%	
	Jun-20	1,218	156	1,373	4,855	0.89	3,177	0.69	3,561	3,404	59%	

a. March 2020 data is not included herein due to low daily coal charge weights.

3.2.5 Ongoing Optimization of FGD System

Cokenergy practices various other emissions minimization steps such as proactive monitoring of the HRSG tube health data to assess when re-tubing may be necessary, routine inspections, cleaning, preventative maintenance schedules, maintain critical spare parts in inventory for repairs, and following best practice for equipment start-up and shutdowns.

Cokenergy has been working with Primex[20] for over 5 years to monitor and optimize utilizing their FGD Performance Assurance Program.

- Monthly tasks completed by Primex
  - Provide and analyze corrosion coupons.
  - Publish monthly report with key performance indicators (KPI) and progress towards goals.
  - Obtain data, analyze performance, and interpret change.
  - Identify potential safety, reliability, and efficiency issues.
  - Perform first layer of troubleshooting.

[20] Primex is an engineering consultant firm specializing in optimization of FGDs.

- Provide actions and recommendations.
- Conference call with Cokenergy team to review findings.

► Quarterly tasks completed by Primex
- Analyze pebble lime and lime slurry samples.
- On-site meeting with Cokenergy team.
- Identify and agree on improvement opportunities.
- Prioritization of actions and assignment of resources.
- Update strategy and action plan.

► Current action plan between Cokenergy and Primex
- Evaluating the inlet temperature effects on SDA residence calculation.
- Determining the best method to automatically control approach temperature based on atomizer(s) conditions.
- Evaluating:
  - ♦ Sorbent preparation control system.
  - ♦ Long-term ash moisture testing options for approach temperature control.

4. TECHNICAL FEASIBLTY – FOUR-FACTOR ANALYSIS

A Four-Factor Analysis for any emission source, such as Cokenergy's FGD system begins with an assessment of technical feasibility in order to determine which emission control measures to reasonably consider with respect to emission-related factors and cost. This aligns with EPA's guidance which states:[21]

> *The first step in characterizing control measures for a source is the identification of technically feasible control measures for those pollutants that contribute to visibility impairment. Identification of these measures does not create a presumption that one of them will be determined to be necessary to make reasonable progress. A state must reasonably pick and justify the measures that it will consider, recognizing that there is no statutory or regulatory requirement to consider all technically feasible measures or any particular measures. A range of technically feasible measures available to reduce emissions would be one way to justify a reasonable set.*

Based on this guidance, Cokenergy has provided background information throughout this report and below which identifies actions already completed at Cokenergy to support the increased effectiveness of existing control techniques that are the most technically feasible and reasonable methods for Cokenergy's FGD system. As noted throughout this report, Cokenergy has already implemented FGD optimization measures at extensive capital cost which have resulted in significant SO_2 reductions.

Consequently, to the extent any additional controls of SO_2 may be considered to meet the RH program reasonable progress requirements, Cokenergy has already implemented those controls through the FGD optimization measures and the realized SO_2 emission reductions.

4.1 Current Baseline Control Scenario

At present, the Cokenergy FGD system at the Arcelor-IH facility consists of two (2) SDAs and two (2) fabric filter baghouses, additional details and description of the system are in Section 3.1. The current permit limits and actual emissions for 2018 for Stack 201, the exhaust of FGD system, are presented in Table 4-1.

Table 4-1. Cokenergy FGD Permit Limits and Annual Emissions

Unit	Pollutant	Limit[a]	Actual Emissions (TPY)[b]
			2018
FGD Stack 201	SO_2	Combined with the sixteen (16) vents from the IHCC of a twenty-four (24) hour average emission rate of one thousand six hundred fifty-six (1,656) pounds per hour	5,398

a. Condition D.1.2(a) T089-41033-00383 issued May 8, 2019.
b. Actual emissions as submitted in 2018 Annual Emission Inventory.

4.2 Technical Feasibility Assessment of Additional SO_2 Control Measures

In Cokenergy's response to IDEM's request to complete a Four-Factor Analysis for the Facility, four (4) SO_2 reduction options for its FGD system were evaluated to determine technical feasibility.

[21] EPA memorandum- Guidance on Regional Haze State Implementation Plans for Second Implementation Period, August 2019.

- Additional FGD system.
- Complete replacement of existing FGD system.
- Addition of end-of-pipe controls to existing FGD system.
- Federally enforceable SO_2 limit.

The technical feasibility of these options is detailed below.

4.2.1 Addition of Second FGD System

As part of the two (2) detailed and comprehensive engineering studies previously completed by Cokenergy an initial review of an additional FGD system that contained one (1) SDA was evaluated as part of a comprehensive site-specific engineering evaluation.

Based on the exorbitantly high capital costs, increased maintenance requirements, expected chemical/reagent usage, difficulties related to physical space and positioning of an additional FGD system, and lack of available footprint at Cokenergy[22] it was determined that the addition of a second FGD system is a technically infeasible option. Indeed, the physical space limitations, among other things, were extensively discussed as part of the negotiations with EPA and IDEM to resolve the Consent Decree. Figure 4-1 shows Cokenergy's property boundaries to illustrate the limited space and challenges that would arise with the addition to control devices.

None of the parameters used to eliminate an additional FGD as technically feasible during the previous engineering studies have changed; therefore, the addition of a second FGD system remains technically infeasible.

[22] Cokenergy operates on a small leased portion, less than one (1) percent of the total acreage of Arcelor-IH's expansive facility and is not contractually allowed to expand outside of established physical boundaries.

Figure 4-1. Cokenergy Property Boundaries

4.2.2 Complete Replacement of FGD System

The EPA Four-Factor Analysis guidelines do not require EGUs with existing FGD systems to remove existing controls and replace them with new controls, but the guidelines do state that coal fired EGUs with existing SO_2 controls achieving removal efficiencies of less than 50% should consider constructing a new FGD system in addition to evaluating the suite of upgrade options. For EGUs, the suite of available "upgrades" may not be sufficient to remove significant SO_2 emissions in a cost-effective manner, and States may determine that these EGUs should be retrofitted with new FGD systems.[23]

Cokenergy is not an EGU but has already undergone extensive enhancements to the existing FGD system and now achieves SO_2 control of more than 50%, as shown in Table 3-1. As Cokenergy's existing enhanced FGD system achieves SO_2 removal efficiency greater than the EPA Four-Factor Analysis guidelines for EGUs, a complete replacement of the FGD system is not evaluated further. Additionally, as the flue gas from IHCC is variable by nature, a new FGD system may not achieve more than nominal SO_2 removal efficiency over the existing, fully optimized, FGD system Cokenergy currently operates.

Accordingly, a complete replacement of the existing FGD system at the Facility is unnecessary and technically infeasible.

[23] 70 FR 39122.

4.2.3 Addition of End-of-Pipe Controls to Existing FGD System

The two categories of control technologies that are used to control flue gas containing SO_2 are wet FGD and dry FGD. The technical feasibility of each control technology category is assessed.

4.2.3.1 Addition of Wet FGD after Existing FGD System

Within the wet FGD control technology category a possible device is a wet scrubbing system, wet scrubber, which utilizes a ground alkaline agent, such as lime or limestone, in slurry (i.e., scrubbing liquid) to remove SO_2 from stack gas via absorption into droplets of slurry which are sprayed countercurrent to flue gas flow via low pressure, large orifice spray nozzles into a reactor vessel. The spent scrubbing liquid is sent to hydroclones to separate gypsum from the recirculated liquor and the hydroclone underflow is sent to a drum filter or belt press to separate solids. Water and the spent solids, consisting of reaction products such as calcium sulfate when lime or limestone is utilized, would be sold or landfilled after dewatering. Recovered water is typically reused to blend new slurry for the wet scrubber along with makeup water to maintain optimal scrubber design removal efficiency. Wet systems typically have greater space requirements and can produce aerosol emissions of entrained PM. Key wet scrubbing operating parameters include residence time and pressure differential in the reactor vessel, liquid flow rate for target liquid-to-gas ratio, scrubber liquid pH and specific gravity, and surface area.

4.2.3.2 Addition of Dry FGD after Existing FGD System

An industry standard dry FGD technology is DSI. A DSI system involves injection of dry alkaline sorbent/reagent into a flue gas stream in exhaust ductwork to create contact between the solid reagent and acid gases. Calcium hydroxide [$Ca(OH)_2$] otherwise known as hydrated lime, is involved in the following chemical reactions:

$$Ca(OH)_2 + SO_2 + 0.5O_2 \rightarrow CaSO_4 + H_2O$$
$$Ca(OH)_2 + SO_2 \rightarrow CaSO_3 + H_2O$$

The gaseous pollutants are bound to the surface of the introduced solid, forming a reaction product, which is separated from the flue gas as PM via capture in a fabric filter after the scrubbing process. Dust cake on the bags acts as a second scrubbing stage in which residual acids receive a final step of scrubbing. Factors affecting the efficiency of the absorption process include flue gas temperature, concentration of SO_2 in the exhaust stream, particle size/surface area of the hydrate, flue gas moisture, and stoichiometric ratio of reagent to SO_2 (Ca/S molar ratio).

4.2.3.3 Technical Feasibility of Additional End-of-Pipe Controls to Existing FGD

The addition of any add-on controls to the existing optimized FGD system is not technically feasible. During previously conducted engineering studies and continuing optimization of the FGD by Primex no additional controls have been identified as viable or feasible.

Both the wet and dry FGD control options are deemed technically infeasible for the provided reasons:

- No physical space to install additional control devices. Cokenergy operates as a contractor to Arcelor-IH and there is no room for expansion as Cokenergy is surrounded by Arcelor-IH processes or other on-site contractors with limited space (e.g., IHCC).

- Cokenergy would likely need to install a dedicated wastewater treatment facility to process the waste streams for any end-of-pipe control additions. The capital costs and physical area restrictions deem this infeasible.[24]
- Addition of end-of-pipe controls could impact the current control efficiency achieved by the FGD system Cokenergy operates. It is undeterminable if additional controls could be added before or after the baghouse system already in place. Extensive retrofitting would need to be conducted for either placement option.

4.2.4 Federally Enforceable SO_2 Limit

Accepting a federally enforceable emissions limitation for SO_2 is an EPA-accepted approach to preclude triggering a Four-Factor Analysis and thereby show reasonable progress for the impacted Class I Areas. However, a new federally enforceable emissions limitation is inappropriate.

First as discussed above, using the PSAT modeling data generated by VISTAS, states identified sources shown to have a sulfate or nitrate impact on one or more Class I areas that is greater than or equal to 1.00 percent of the total sulfate plus nitrate point source visibility impairment on the most impaired days for that Class I area. This analysis did not identify Cokenergy as a point source that meets the criteria in the VISTAS PSAT modeling. Consequently, VISTAS modeling does not indicate an additional SO_2 limit at Cokenergy would improve visibility at Mammoth Cave or is otherwise required to meet RH regulations.

In addition, there already is a federally enforceable limit of 1,656 lb SO_2/hr in Title V, T089-41033-00383, permit condition D.1.2(a) and additional federally enforceable SO_2 limits raise significant feasibility issues. A federally enforceable limit restricting annual venting (and thereby reducing SO_2 emissions) was accepted as a result of extensive, multi-year CD negotiations and was ultimately incorporated into both Cokenergy's Title V permit and the Indiana SIP. The limit represented the emissions reductions EPA and IDEM believed were feasible while taking into account the need for operational flexibility and routine and non-routine maintenance needs.

Thus, it was understood by all parties that maintaining the 1,656 lb SO_2/hr emission limit is a vital aspect of the Cokenergy Facility's ability to maintain compliance with its Title V permit under a variety of operating conditions.

[24] Cokenergy does not have access to Arcelor-IH wastewater treatment.

5. FOUR-FACTOR ANALYSIS OF TECHNICALLY FEASIBLE SO_2 CONTROL OPTIONS

Based on the analysis above, Cokenergy's view is that no additional controls are necessary or technically feasible. Throughout this report and below, the Facility has provided details, as applicable, to the four-statutory RH factors. The preceding sections of this analysis document the optimization projects Cokenergy has undertaken beginning in 2010 with re-tubing the HRSGs and continues through the present with the ongoing support Primex provides the Facility. These projects, the resources expended to implement the projects, and the impact of the projects on the Facility's SO_2 emissions should be considered in IDEM's RH reasonable progress analysis to be submitted to EPA Region 5. In addition, the fact that there is no visibility impact from the Facility's SO_2 emissions on Mammoth Cave should also be considered in IDEM's RH reasonable progress analysis to be submitted to EPA Region 5.

5.1 Cost of Compliance (Statutory Factor 1)

A cost of compliance analysis was not conducted for this report as additional controls are unnecessary and infeasible. As previously noted, Cokenergy made a substantial capital investment exceeding $41 million to optimize the company's FGD system, which resulted in significant SO_2 reductions. In addition, Cokenergy could not accommodate the additional space required for additional control equipment, storage of reagents that would be required for additional control equipment, additional electric power needed, or disposal/treatment of blowdown wastewater.

In addition, as part of this Four-Factor Analysis, Cokenergy reviewed the EPA Air Pollution Control Cost Manual Section 5 Chapter 1 – Wet Scrubbers for Acid Gas for SO_2 (the Manual). The Manual has been utilized throughout Indiana and nationally as a screening tool for Statutory Factor 1. The input parameters for both wet and dry FGD require data that are not applicable to Cokenergy, as fuel is not combusted as part of Cokenergy's process. Cokenergy receives only waste heat from IHCC. Additionally, the coal that IHCC uses to produce coke is elementally different from coal typically combusted at EGUs which disallows the usage of default coal factors (e.g., lignite, subbituminous, anthracite) from the Manual.

Representative inputs in the Manual:

- Higher heating value of fuel blend
- Nameplate maximum heat input to boiler
- Net plant heat rate of system
- Fuel type combusted and coal type, as applicable

As noted previously in this report, Cokenergy engaged in an extensive engineering review which included cost information before selecting an option to optimize the Facility's FGD system. EPA and IDEM agreed with this determination in the course of CD negotiations. Conducting an additional cost of compliance analysis at this time using the Manual is infeasible in the allotted time given the unique, site specific factors involved. Cokenergy would require additional time from IDEM to develop a site-specific cost estimate that would require contracting with an engineering design firm. Nevertheless, as discussed throughout this report, any additional control technologies for Stack 201 are unnecessary and technically infeasible for all the reasons stated herein.

5.2 Time Necessary for Implementation (Statutory Factor 2)

As no controls are considered technically feasible for Cokenergy, implementation of the controls is not an applicable step. If additional SO_2 control was required for RH visibility reasonable progress, Cokenergy would engage contractors for further engineering analysis/study, which would take several years.

5.3 Energy & Non-Air Quality Environmental Impacts (Statutory Factor 3)

As no controls are considered technically feasible for Cokenergy, an in-depth analysis of energy and non-air quality environmental impacts was not conducted.

5.4 Remaining Useful Life (Statutory Factor 4)

As no controls are considered technically feasible for Cokenergy, there is no add-on control technology life to consider.

6. RECOMMENDATIONS

As noted in this report, no additional SO_2 control measures by Cokenergy are necessary for IDEM to meet the RH Program requirements. Indeed, Cokenergy has already implemented significant SO_2 reduction measures through the FGD optimization program at significant capital cost. Furthermore, there is no indication from VISTAS photochemical modeling that Cokenergy is causing significant impact (or any impact at all) on Class I areas (Section), including the Class I area at issue here—Mammoth Cave. Finally, as it pertains to the four factors of the second RH planning period, there are no additional reasonable SO_2 control options for the lime spray dryer FGD unit located at Arcelor-IH. Cokenergy will continue to operate the FGD system following the optimization strategies already in place that will continue to enhance the SO_2 reduction from Stack 201.

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Appendix G

SABIC Four-Factor Analysis Submittal

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September 30, 2020

VIA EMAIL

Ms. Jean Boling
Indiana Department of Environmental Management
Office of Air Quality
100 North Senate Avenue, IGCN 1003
Indianapolis, IN 46204

RE: Regional Haze
Request for Four-Factor Analysis
SABIC INNOVATIVE PLASTICS MT. VERNON, LLC
Mt. Vernon, Indiana

Dear Ms. Boling,

Please find attached the requested Four-Factor Analysis for the SABIC Innovative Plastics Mt. Vernon, LLC (SABIC) site at Mt. Vernon, Indiana.

Should you have any questions or concerns, please contact me at (217) 521-1799 or by e-mail gregory.michael@sabic.com.

Sincerely,

Greg Michael
Environmental Manager

Attached

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REGIONAL HAZE FOUR-FACTOR ANALYSIS

SABIC Innovative Plastics / Mt. Vernon, IN

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September 2020

Project 2018001.0012

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1. EXECUTIVE SUMMARY

This report was prepared on behalf of SABIC Innovative Plastics Mt. Vernon LLC (SABIC) for its plastics manufacturing facility located in Mt. Vernon, Indiana (MtV) as the response to the June 2020 request from Indiana Department of Environmental Management's (IDEM's) Regional Haze State Implementation Plan Second Planning Period Request for Four-Factor Analysis letter. IDEM requested that SABIC's MtV facility prepare a four-factor analysis per Section 169a(g)(1) of the Clean Air Act (CAA) to support IDEM's development of a revised Regional Haze State Implementation Plan (SIP) for the second planning period, 2018 to 2028. The second planning period SIP is due for submission to Region 5 of the U.S. Environmental Protection Agency (EPA) by July 31, 2021.[1]

As detailed in IDEM's four-factor analysis request, the MtV facility operates two (2) sources for which IDEM requested a four-factor analysis, identified as the Co-generation unit (COGEN) and Phosgene COS Vent Oxidizer (COS Vent Oxidizer) and flare associated with Building 6 carbon monoxide generators.[2] This report provides information related to effective and reasonable control measures in light of cost and time necessary for implementation, energy and non-air quality impacts, and remaining useful life of equipment for sulfur dioxide (SO_2) emissions from both COGEN and COS Vent Oxidizer and nitrogen oxides (NO_X) emissions from only COGEN.

The following specific technical and economic information, where applicable, is provided in this report for each emissions reduction option considered, in accordance with instructions in the four-factor analysis request:

- Identification of technically feasible options
- Costs of compliance[3] (Statutory Factor 1)
- Time necessary for compliance[3] (Statutory Factor 2)
- Energy and non-air quality environmental impacts of compliance[3] (Statutory Factor 3)
- Remaining useful life of affected sources [3] (Statutory Factor 4)

[1] 40 CFR 51.308(f)

[2] The COS Flare is a backup control device to the COS Vent Oxidizer (it is also used during safety interlock of the CO generator system to the COS Vent Oxidizer; therefore, this report focuses on a four-factor analysis to reduce SO_2 emissions from the COS Vent Oxidizer only. Adding end-of-pipe control to the COS Flare could impact the COS/VOC removal efficiency of the flare and was not assessed in this report.

[3] These are the four factors that must be included in evaluating emission reduction measures necessary to make reasonable progress determinations pursuant to 40 CFR 51.308(f)(2)(i). Additionally, identification of technically feasible options as well as assessments of technical feasibility, control effectiveness, and emissions reductions are required to assess the cost of implementation.

2. FACILITY AND PROCESS DESCRIPTIONS

The following offers background on SABIC's MtV facility and the applicable process operations IDEM included in their four-factor analysis request to SABIC. To align with IDEM's requested four-factor analysis, SABIC will only describe the process operations identified in the June 2020 request letter (i.e., COS Vent Oxidizer and COGEN).

2.1 Facility Description

The MtV facility was built in 1960 to produce Lexan™ Resin on 150 acres of land. Currently, the site encompasses 1,100 acres and has expanded its chemical and plastics manufacturing operations to manufacture numerous products that are sold to end-use customers. MtV manufactures many intermediate products necessary for end-use plastics products. These intermediates are used at MtV and other SABIC facilities prior to reaching the marketplace. The site's extensive product portfolio includes thermoplastic resins, coatings, specialty compounds, and plastics film/sheet.

2.2 Process Operation Descriptions

2.2.1 Phosgene Process Description

The Phosgene process area, Section I of SABIC's current Title V[4] permit 129-42984-00002, generates phosgene, which is a key intermediate to produce polycarbonate. Polycarbonate is an end-use plastic with countless purposes in many impactful industries (e.g., medical, automotive). The chemical reaction to generate phosgene ($COCl_2$) is shown by the following equation.

$$CO + Cl_2 \rightarrow COCl_2$$

The COS Vent Oxidizer, one of the two emission units requested by IDEM to conduct a four-factor analysis, controls the production of carbon monoxide (CO). The chlorine (Cl_2) gas is generated in another process area within the MtV facility. Cl_2 gas production is not discussed in this report as it is not included in IDEM's four-factor analysis request.

The major process steps to produce purified CO, an essential step in producing phosgene, are described as follows:

- The CO generation process involves the controlled combustion of petrochemical coke (petcoke) to form CO. The petcoke contains sulfur as an impurity. During the controlled combustion process, the sulfur is converted to reduced sulfur compounds containing organic sulfides. The organic sulfides primarily consist of carbonyl sulfide (COS), hydrogen sulfide (H_2S), and carbon disulfide (CS_2).[5]
- The generated CO and organic sulfides are passed through a carbon bed that adsorbs the organic sulfides present.
- The carbon bed adsorbers are periodically regenerated by purging the beds to desorb the sulfides.

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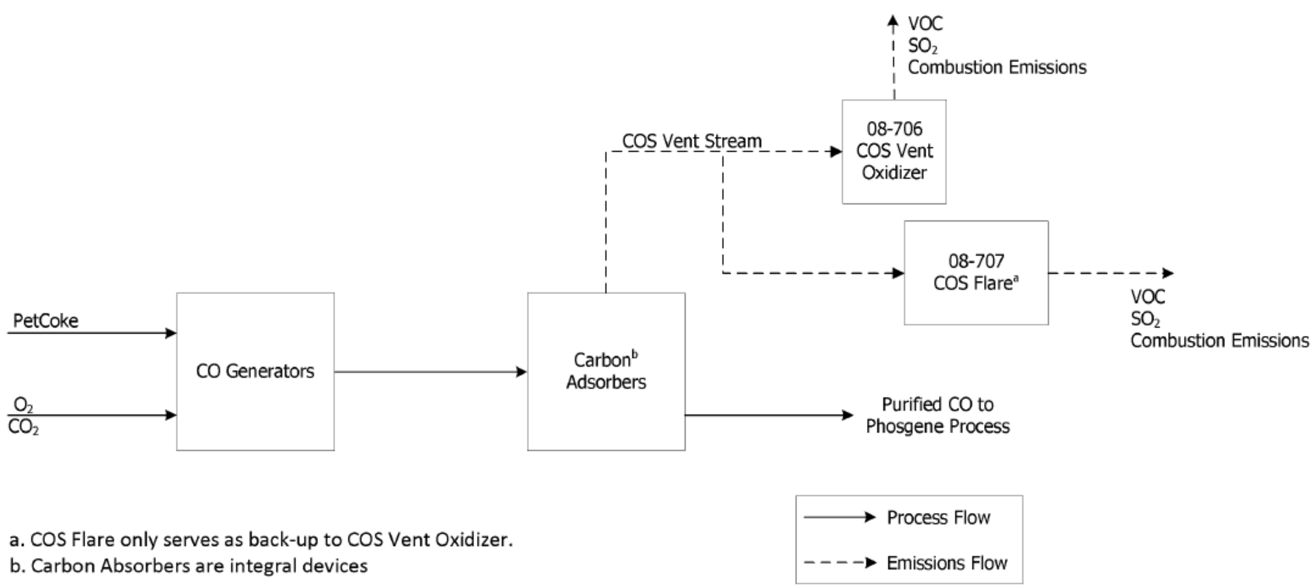
[4] SABIC's most recently issued Title V permit (129-42984-00002 from August 17, 2020) was for a minor source modification/administrative amendment.

[5] The facility description box in Section I.2 of SABIC's Title V permit notes the COS vent stream contains organic sulfides, which primarily consist of carbonyl sulfide, hydrogen sulfide, and carbon disulfide.

- During the regeneration of the carbon adsorbers the organic sulfides are removed from the carbon and become part of the regeneration gas stream referred to as the COS vent stream.
- The COS vent stream from the carbon bed adsorbers[6] is routed to the COS Vent Oxidizer (Stack Vent ID 08-706).
- The SO_2, the pollutant addressed in this four-factor analysis, is a byproduct created during the incineration of the COS vent stream in the COS Vent Oxidizer.
- Figure 2-1 represents SABIC's existing air pollution control scenarios for controlling the organic sulfides in the COS vent stream that originated during CO generation.

Figure 2-1. Process Flow Diagram for CO Generation in Phosgene Process Area



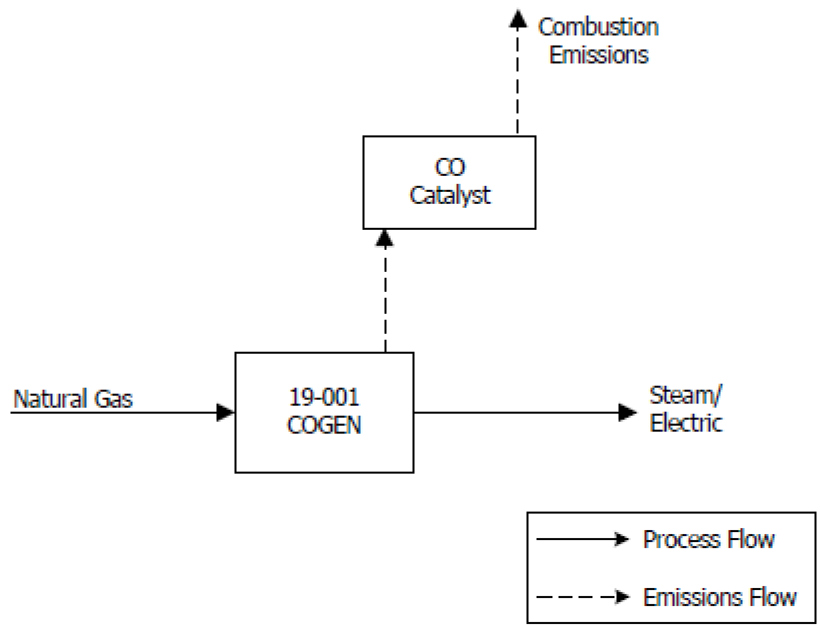
2.2.2 Co-generation Facility Process Description

The co-generation facility at MtV began construction in 2015 and was fully operational in the fourth quarter of 2016. The installation of the 1,812 MMBTU per hour (MMBTU/hr) stationary natural gas-fired combustion turbine and nominal 486 MMBTU/hr natural gas-fired duct burner with a heat recovery steam generator (HRSG) allowed SABIC to cease using coal as fuel to generate steam for process operations.

IDEM requested SABIC to conduct a four-factor analysis for both SO_2 and NO_X emissions from the COGEN unit, Stack Vent ID 19-001. Figure 2-2 represents the process flow for the COGEN unit.

[6] The carbon adsorbers are listed as integral devices in Section I.2 of SABIC's Title V permit, T129-36775-00002, V-948, V-949, V-050A, V-951A, V-9020, and V-9021.

Figure 2-2. Process Flow Diagram for COGEN



3. REGIONAL HAZE PROGRAM IN INDIANA

3.1 Regional Haze Program

Pursuant to 40 CFR 51.308(d), each state must address regional haze in each mandatory Class I Federal area located within the state, and each area outside the state if affected by interstate emissions. States must establish reasonable progress goals that provide for an improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period. The regional haze program is within the second planning period (2018-2028).

3.2 IDEM's Analysis Request to SABIC

IDEM sent SABIC a four-factor request letter, via email, on June 18, 2020 which included the list of emission units to be included in the four-factor analysis. IDEM's request of SABIC included:

Table 3-1. Emission Units and Pollutants in IDEM's Four-Factor Analysis Request to SABIC [a]

Emission Unit	Type of Four-Factor Analysis
Co-generation unit	SO_2 and NO_X
Phosgene COS vent oxidizer and flare associated with Building 6 carbon monoxide generators	SO_2

a. This table was presented by IDEM in the June 18, 2020 Regional Haze State Implementation Plan Second Planning Period Request for Four-Factor Analysis letter sent to SABIC via email on June 18, 2020.

IDEM described their selection methodology to request four-factor analyses for facilities in Indiana during the June 3, 2020 webinar. To summarize the information presented, IDEM selected steel mills, cement kilns[7], and non-electric generating utility (EGU) sources[8] with a "Q/d" greater than 5.0 to complete or request completion of a four-factor analysis. IDEM indicated the "Q/d" approach was chosen to include a reasonable number of sources to be evaluated and for consistency with other Lake Michigan Air Directors Consortium (LADCO) states. LADCO is a regional planning organization (RPO) and includes Indiana, Illinois, Ohio, Wisconsin, and Michigan.

IDEM based inclusion of sources in this second implementation period of regional haze planning on a ratio of 2018 actual annual emissions of visibility-affecting pollutants (determined by IDEM to be NO_X and SO_2 for Indiana), known as "Q" in tons per year (tpy), and distance to Class I[9] area, known as "d" in kilometers (km). IDEM has selected the conservative ratio criteria of "Q/d > 5.0" to identify the facilities for which four-factor analyses will be completed. Based on this screening approach, IDEM calculated the "Q/d" to be 5.3[10] for SABIC which led to IDEM's request that SABIC develop a four-factor analysis.

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[7] IDEM indicated the completion of the four-factor analyses for the two cement facilities in Indiana with a "Q/d > 5.0" (Lehigh Cement Company and Lone Star Industries Inc) was undertaken internally.

[8] SABIC falls into the non-EGU category.

[9] Class I areas are designated by the CAA which gave special air quality and visibility protection to national parks larger than 6,000 acres and national wilderness areas larger than 5,000 acres that were in existence when the CAA was amended in 1977.

[10] Actual 2018 site-wide SO_2 and NO_X emissions of 965 tpy with a distance of 182 km to Mammoth Cave NP (965 Q / 182 d = 5.292).

The "Q/d" selection criterion is the least complicated technique offered in the guidance memorandum by EPA on Regional Haze SIP for the Second Implementation Period.[11] The selection criteria offered by EPA are as follows, ranked in order of least to most complex:

- Emissions divided by distance (Q/d) – Ratios SO_2 and NO_X emissions with distance to Class I areas.
- Trajectory analyses – Examines the wind direction on individual days.
- Residence time analyses – A trajectory-based analysis technique that combine emissions, ambient particulate data, and trajectory information.
- Photochemical modeling (zero-out and/or source apportionment) – The only modeling technique suggested by EPA. Photochemical modeling quantifies source or source sector visibility impacts.

Although the "Q/d" selection technique is easy to implement, it does not include as much information as the three (3) more complex selection techniques suggested by EPA. The more sophisticated techniques account for detailed information on particulate matter (PM), and PM species impacts but are more resource intensive. EPA allowed each state to select their own four-factor analysis selection techniques and did allow states to use other reasonable techniques.

IDEM's "Q/d >5.0" selection criterion does not account for the data analyzed (i.e., photochemical modeling) and summarized by RPOs. RPO modeling results do not indicate SABIC has a sulfate or nitrate impact on Mammoth Cave greater than or equal to 1.00 percent of the total sulfate plus nitrate point source visibility impairment on the twenty (20) percent most impaired days. This criterion is used to include or exclude, in SABIC's case, emissions from a point source as within the Area of Influence (AoI) of a Class I area.

3.3 VISTAS Modeled Class I Impacts Outside LADCO RPO

SABIC is physically located in the RPO of LADCO although the only Class I area IDEM referred to in the June 2020 request letter is Mammoth Cave, which is in Kentucky. Kentucky is located within the Visibility Improvement State and Tribal Association of the Southeast (VISTAS). VISTAS is a subcommittee of the Southeastern Air Pollution Control Agencies (SESARM) RPO. VISTAS conducted technical analyses to help states identify sources that significantly impact visibility impairment for Class I areas within and outside the VISTAS region (i.e., VA, WV, NC, SC, GA, FL, AL, TN, MI, KY, GA). VISTAS conducted an AoI analysis to identify sources to "tag" for PM Source Apportionment Technology (PSAT) modeling, which was implemented with the Comprehensive Air Quality Model with Extensions (CAMx) analysis to identify emissions sources that strongly contribute to regional haze.[12] VISTAS identified three (3) impactful sources in Indiana[13] as a result of this analysis, all EGUs, and they did not include SABIC.[14] Therefore, the VISTAS's analyses concluded that SABIC's facility in Mt. Vernon, Indiana was not a source shown to have a significant sulfate or nitrate impact on a Class I area.

[11] EPA memorandum- Guidance on Regional Haze State Implementation Plans for Second Implementation Period, August 2019.

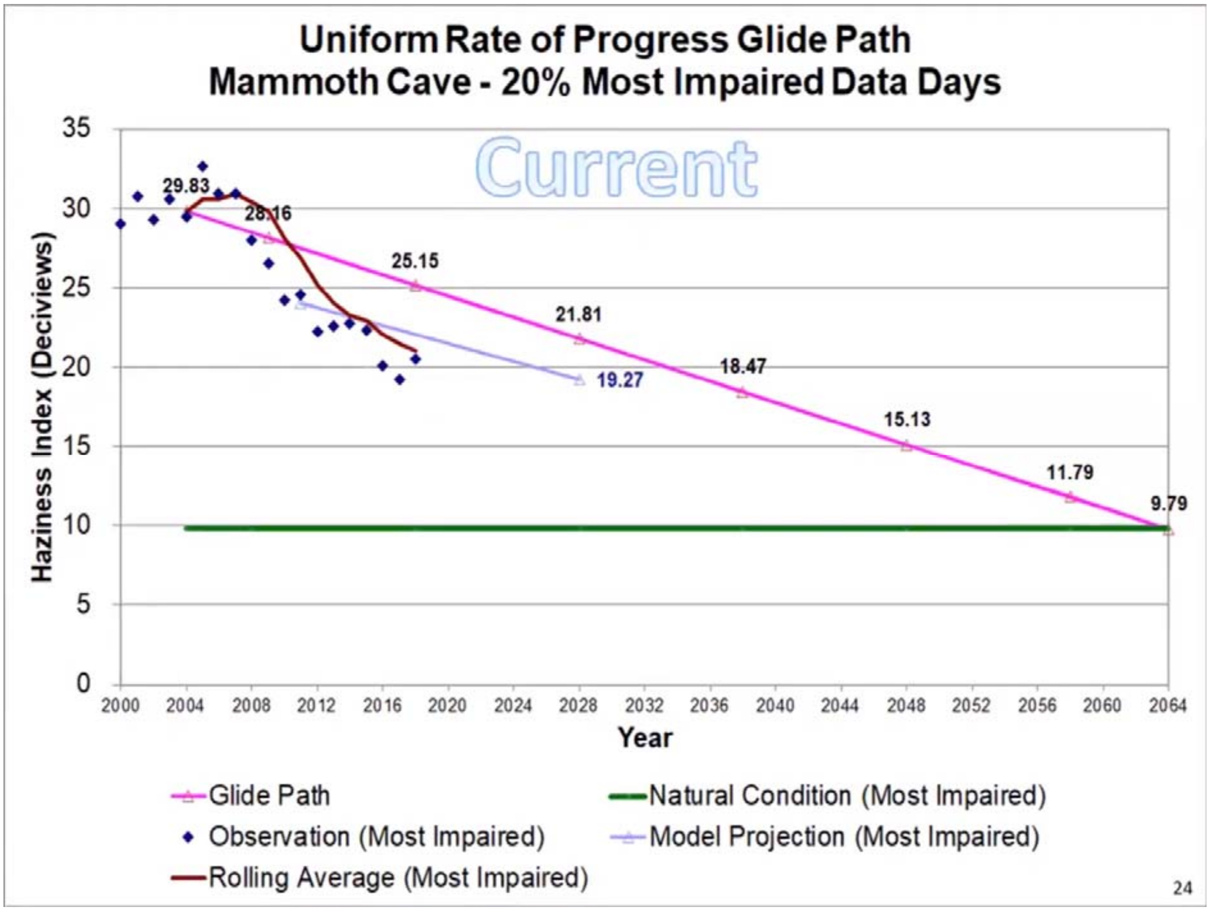
[12] Defined by VISTAS as sources shown to have a sulfate or nitrate impact on one or more Class I areas greater than or equal to 1.00% of the total sulfate plus nitrate point source visibility impairment on the 20% most impaired days for each Class I area.

[13] VISTAS identified Indianapolis Power & Light Petersburg (18125-73624111), Gibson (18051-7363111), and Indiana Michigan Power DBA AEP Rockport (18147-9017211) as the Indiana sources shown to have a sulfate or nitrate impact on one or more Class I areas greater than or equal to 1.00 percent of total sulfate plus nitrate point source visibility impairment on the 20 percent most impaired days for each Class I area.

[14] VISTAS Letter- Request for Regional Haze Reasonable Progress Analyses for Indiana Sources Impacting VISTAS Class I Areas, June 2020.

In addition, VISTAS updated 2028 CAMx modeling based on actual observations through 2018 and revised future projections based on reasonable progress.[15] As indicated in Figure 3-1, current visibility conditions and projected visibility conditions at Mammoth Cave are better than the target uniform rate of progress (URP) glidepath line. Therefore, emission reductions are not required to meet the 2028 uniform rate of progress goal for visibility at Mammoth Cave.

Figure 3-1. VISTAS Haziness Index Modeling Results – Mammoth Cave Class I Area



With the data presented, and detailed in this report, it can be concluded that emissions from SABIC do not impact Mammoth Cave. SABIC is fulfilling IDEM's request by submitting this four-factor analysis report, although no current data indicates the site significantly impacts Class I visibility.

[15] VISTAS presentation- Regional Haze Project Update- EPA, FLM, RPO Briefing https://youtu.be/FN83NmV0JWQ , August 2020.

4. TECHNICALLY FEASIBLE CONTROL MEASURES IDENTIFICATION

This section describes the baseline controls currently in use and the potential add-on controls for SO_2 and NO_X at the MtV facility.

4.1 Baseline Control Scenario

At present and as required by SABIC's current Title V permit, the following controls are in operation for the units in IDEM's four-factor analysis request:

- The COS Vent Oxidizer is itself a control device. It controls the carbon adsorbers that are integral control devices to the CO generators 1 to 16 as described in the permit's Section I.2 facility description box. The COS Vent Oxidizer reduces volatile organic compounds (VOC) from the COS vent stream.
- COGEN combusts only natural gas, a low-sulfur fuel. An oxidation catalyst controls both CO and VOC emissions from the stationary combustion turbine and HRSG. A low-NO_X duct burner was installed as well.

Table 4-1. SABIC Mt. Vernon – Four-Factor Analysis Emission Units, Permit Limits, and Actual Annual Emissions

Emission Unit (Stack/Vent ID)	Description	Pollutant	Permit Limits in TV 129-42984-00002	2018 Emissions (tpy)
COS Vent Oxidizer (08-706)	Phosgene COS vent oxidizer and flare associated with Building 6 CO generators	SO_2	Condition I.2.1(c and d) COS vent stream is being vented to COS Vent Oxidizer or Flare total sulfur input to CO generators shall be limited to 928.65 tons per 365-day period rolled on daily basis	570 [a]
COGEN (19-001)	1,812 MMBTU/hr stationary natural gas-fired combustion turbine including a nominal 486 MMBTU/hr natural gas-fired duct burner and HRSG	NO_X	No site-specific limits; W.2.8 and 9 establish NSPS Subpart KKKK as permit limits	119 [b]
		SO_2	No site-specific limits; W.2.10 establish NSPS Subpart KKKK as permit limits	2.3 [a]

a. Actual emissions calculated using accepted and standard methodologies for applicable emission units and reported in SABIC's 2018 annual emission summary submitted to IDEM.
b. NO_X emissions for COGEN use continuous emission monitoring system (CEMS) data.

4.1.1 Baseline SO_2

4.1.1.1 CO Generation Process SO_2 Emissions

The SO_2 emissions from the CO generation process are created during the incineration of the COS vent stream in the COS Vent Oxidizer. The COS vent stream, containing reduced sulfur compounds, predominately originates from the reduction of carbon dioxide (CO_2) over petcoke to generate purified CO.

The MtV facility operates sixteen (16) CO generators to produce a high-purity CO as an intermediate to be used for phosgene generation in the Phosgene process area. The sulfur content of the petcoke is analyzed frequently by MtV or the petcoke supplier. A mass balance of the total sulfur input to the CO generators is required in MtV's current Title V permit Condition I.2.3(c) to comply with the Prevention of Significant Deterioration (PSD) avoidance limit in Condition I.2.1. The SO_2 that exits the COS Vent Oxidizer originates as sulfur in the petcoke.

4.1.1.2 COGEN SO_2 Emissions

The four-factor analysis request from IDEM included SO_2 emissions from COGEN. However, COGEN is a natural gas-fired combustion turbine that has inherently low SO_2 emissions due to the small amount of sulfur present in the fuel. SABIC receives pipeline quality natural gas which pursuant to 40 CFR 72.2 must contain 0.5 grains/100 standard cubic foot (SCF) or less of sulfur.

> *40 CFR 72.2 - Pipeline natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions, and which is provided by a supplier through a pipeline. Pipeline natural gas contains 0.5 grains or less of total sulfur per 100 standard cubic feet. Additionally, pipeline natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 Btu per standard cubic foot.*

The low sulfur input into COGEN results in low SO_2 emissions at the COGEN stack (i.e., post combustion).

4.1.2 Baseline NO_X[16]

The only emission unit at SABIC for which IDEM requested a four-factor analysis for NO_X is SABIC's COGEN; therefore, this section describes the NO_X emissions from the stationary natural gas-fired combustion turbine with a natural gas-fired duct burner and HRSG.

NO_X formation occurs by three fundamentally different mechanisms. The principal mechanism with turbines firing natural gas is thermal NO_X, which arises from the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. Most thermal NO_X is formed in high temperature stoichiometric flame pockets downstream of the fuel injectors where combustion air has mixed sufficiently with the fuel to produce the peak temperature fuel to air interface.

The second mechanism, referred to as prompt NO_X, is formed from early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NO_X forms within the flame and is usually negligible when compared to the amount of thermal NO_X formed. The third mechanism, fuel NO_X, stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. Natural gas has negligible chemically bound fuel nitrogen, although some molecular nitrogen maybe present. It can be assumed that all NO_X formed from natural gas combustion is thermal NO_X.

The maximum thermal NO_X formation occurs at a slightly fuel-lean mixture because of excess oxygen available for reaction. The control of stoichiometry is critical in achieving reductions in thermal NO_X. Thermal NO_X formation also decreases rapidly as the temperature drops below the adiabatic flame temperature, for a given stoichiometry. Maximum reduction of thermal NO_X can be achieved by control of both the combustion temperature and the stoichiometry. Gas turbines operate with high overall levels of excess air because

[16] Technical description adapted from AP-42 Chapter 3.1 Stationary Gas Turbines 3.1.3.1 Nitrogen Oxides, as applicable to SABIC.

turbines use combustion air dilution as the means to maintain the turbine inlet temperature below design limits.

Diffusion flames are characterized by regions of near-stoichiometric fuel-air mixtures where temperatures are very high and significant thermal NO_X is formed. Water vapor in the turbine inlet air contributes to the lowering of the peak temperature in the flame; therefore, decreasing thermal NO_X emissions. Thermal NO_X can also be reduced in diffusion type turbines through water or steam injection. The injected water-steam acts as a heat sink lowering the combustion zone temperature thereby reducing thermal NO_X. SABIC's COGEN uses lean, premixed combustion technology. The natural gas is typically premixed with more than 50 percent theoretical air, which results in lower flame temperatures suppresses thermal NO_X formation.

Ambient weather conditions impact NO_X emissions and power output from turbines more than from external combustion systems (e.g., natural gas-fired boilers). The operation at high excess air levels and at high pressures increases the influence of inlet humidity, temperature, and pressure. Variations of emissions of 30 percent or greater have been exhibited with changes in ambient humidity and temperature. Humidity acts to absorb heat in the primary flame zone due to the conversion of the water content to steam. As heat energy is used for water to steam conversion, the temperature in the flame zone will decrease resulting in a decrease of thermal NO_X formation. For a given fuel firing rate, lower ambient temperatures lower the peak temperature in the flame, lowering thermal NO_X significantly. Similarly, the gas turbine operating loads affect NO_X emissions. Higher NO_X emissions are expected for high operating loads due to the higher peak temperature in the flame zone resulting in higher thermal NO_X generated.

SABIC's COGEN is equipped with fully integrated programmable process controls that vary the operational parameters of the unit to reduce thermal NO_X generation. MtV's current Title V permit contains conditions, W.2.8, 9 and 10, that limit COGEN's NO_X emissions to 40 CFR 60 Subpart KKKK-Standards of Performance for Stationary Combustion Turbines. SABIC demonstrates compliance with a NO_X continuous emission monitoring equipment as required by Title V condition W.2.18.

4.2 Four Factor Analysis Technical Feasibility

The four-factor analyses for the COS Vent Oxidizer and COGEN begins with an assessment of technical feasibility to determine what emission control measures to reasonably consider with respect to emission-related factors and cost. This aligns with EPA's guidance which states:[17]

> *The first step in characterizing control measures for a source is the identification of technically feasible control measures for those pollutants that contribute to visibility impairment. Identification of these measures does not create a presumption that one of them will be determined to be necessary to make reasonable progress. A state must reasonably pick and justify the measures that it will consider, recognizing that there is no statutory or regulatory requirement to consider all technically feasible measures or any particular measures. A range of technically feasible measures available to reduce emissions would be one way to justify a reasonable set.*

Based on this guidance, SABIC is providing background information below to support the selection of control measures that IDEM may consider as technically feasible and reasonable for the requested units at the MtV facility.

[17] EPA memorandum- Guidance on Regional Haze State Implementation Plans for Second Implementation Period, August 2019.

4.2.1 Technical Feasibility Assessment of Additional SO_2 Control Measures

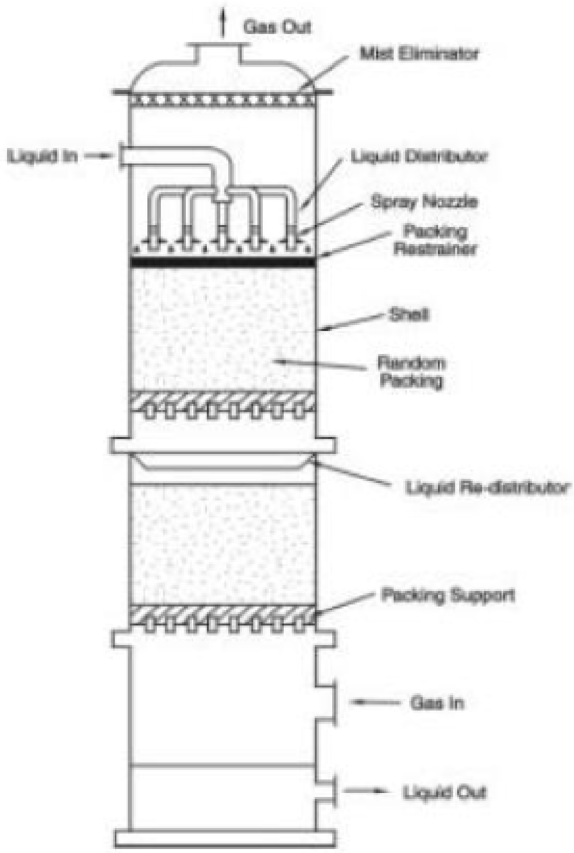
4.2.1.1 Packed-Bed Wet Scrubber[18] for COS Vent Oxidizer SO_2 Control

SABIC has evaluated a packed-bed wet scrubber as a potential technically feasible SO_2 control measure for an end-of-pipe control after the COS Vent Oxidizer.

Packed-bed scrubbers, sometimes referred to as packed-tower scrubbers, consist of a chamber containing layers of variously-shaped packing material (e.g., Raschig rings, spiral rings, or Berl saddles) that provide a large surface area for liquid to particle contact. The packing is held in place by wire mesh retainers and supported by a plate near the bottom of the scrubber. Scrubbing liquid is evenly introduced above the packing and flows down through the bed. The liquid coats the packing and establishes a thin film. The pollutant, SO_2 from the CO generation process, to be absorbed must be soluble in the fluid. In vertical designs (packed towers), the gas stream flows up the chamber (countercurrent to the liquid). Some packed beds are designed horizontally for gas flow across the packing (crosscurrent). Physical absorption depends on properties of the gas stream and liquid solvent (e.g., density and viscosity), as well as specific characteristics of the pollutant in the gas and the liquid stream (e.g., diffusivity, equilibrium solubility). These properties are temperature dependent, and lower temperatures generally favor absorption of gases by the solvent. Absorption is also enhanced by greater contacting surface, higher liquid-gas ratios, and higher concentrations in the gas stream. Chemical absorption may be limited by the rate of reaction, although the rate-limiting step is typically the physical absorption rate, not the chemical reaction rate.

[18] Technical description adapted from EPA Air Pollution Control Technology Fact Sheet-Packed-Bed/Packed-Tower Wet Scrubber, as applicable to SABIC.

Figure 4-1. Packed-Bed Wet Scrubber Schematic



For a packed-bed wet scrubber to control SO_2 emissions from SABIC's COS Vent Oxidizer, pollutant removal may be enhanced by manipulating the chemistry of the absorbing solution so that it reacts with the pollutant. A caustic solution of sodium hydroxide (NaOH) is the most common scrubbing liquid used for acid-gas control such as the COS vent stream at MtV. When the acid gases are absorbed into the scrubbing solution, they react with alkaline compounds to produce neutral salts. The rate of absorption of the SO_2 is dependent upon the solubility of the pollutant in the NaOH scrubbing liquid.

Advantages of a scrubber for SO_2 control as end-of-pipe technology after the COS Vent Oxidizer include:

- Relatively low pressure drop across the scrubber,
- Equipment construction is typically fiberglass-reinforced plastic that operates well in highly corrosive atmospheres,
- Reasonably high mass-transfer efficiencies are achievable,
- Packing inside scrubbers can be changed out to improve mass transfer without purchasing a new scrubber body/shell, and
- Comparatively low capital costs and space requirements.

Of the usual drawbacks to a scrubber for this application, only the blowdown/scrubber waste disposal issues are likely to be of issue to SABIC. Typical disadvantages to scrubbers can be plugging of scrubber media from particulate matter and scrubber construction being sensitive to temperature, both of which are not anticipated for MtV. With proper scrubber pH and temperature control, the potential plugging of the media from precipitation of salts can be avoided.

Wet scrubbing by a packed bed/tower scrubber is considered a technically feasible SO_2 control of the COS vent stream from the COS Vent Oxidizer.

4.2.1.2 Other Gas Absorber (Scrubber) Technologies for COS Vent Oxidizer SO_2 Control

Gas absorbers are generally referred to as scrubbers due to the mechanisms by which gas absorption take place. The term scrubber is often used very broadly to refer to a wide range of different control devices, such as those used to control particulate matter emissions. The term scrubber, in this report, is used to refer to control devices that use gas absorption to remove gases from waste gas streams. There are several SO_2 gas absorption technologies that are intended to control large volume (gas flow rate) and high SO_2 concentration (ppm) emission streams. Typically, these sources combust coal at large EGUs, steel mills, cement kilns, or large industrial boilers which generate a large volume of exhaust with a high SO_2 concentration due to the large amounts of coal combusted in the units.

The two broad categories of scrubber technologies used on large volume/high SO_2 concentration are wet flue gas desulfurization (FGD) and dry FGD. To further qualify the need for a high gas exhaust flow and concentration, EPA's Air Pollution Control Cost Manual (Cost Manual) for SO_2 and Acid Gas Controls requires data inputs such as, fuel higher heating value and boiler output megawatt (MW) rating. Neither of these data inputs are applicable to MtV's COS Vent Oxidizer exhaust stream.

In addition, the EPA air pollution control technology fact sheet for FGD- Wet, Spray Dry, and Dry Scrubbers has the following as the typical industrial applications for this technology.

> *Stationary coal- and oil-fired combustion units such as utility and industrial boilers, as well as other industrial combustion units such as municipal and medical waste incinerators, cement and lime kilns, metal smelters, petroleum refineries, glass furnaces, and sulfuric acid manufacturing facilities.* [19]

The COS Vent Oxidizer exhaust stream does not have a large enough volumetric gas flow rate or sufficiently high SO_2 concentration to make the scrubber technologies in this section technically feasible.

4.2.1.3 SO_2 Reduction for COGEN

COGEN is fueled by low sulfur, pipeline quality, natural gas. While it may be theoretically feasible to install a wet or dry scrubber system on a natural gas-fired turbine such as COGEN, due to the inherently low SO_2 emission concentration associated with the combustion of natural gas, these systems are not cost effective and in Trinity's experience, regulatory agencies do not require such controls or even the evaluation of such controls. Consequently, no further discussion of additional SO_2 controls for COGEN is necessary.

4.2.2 Technical Feasibility Assessment of NO_X Control Measures

SABIC has evaluated the following additional emissions control measures for NO_X reduction for COGEN:

- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)
- Selective Catalytic Oxidizer with additional capability of reducing NO_X emissions (SCONOx™)

The technical feasibility of these options is discussed in this section.

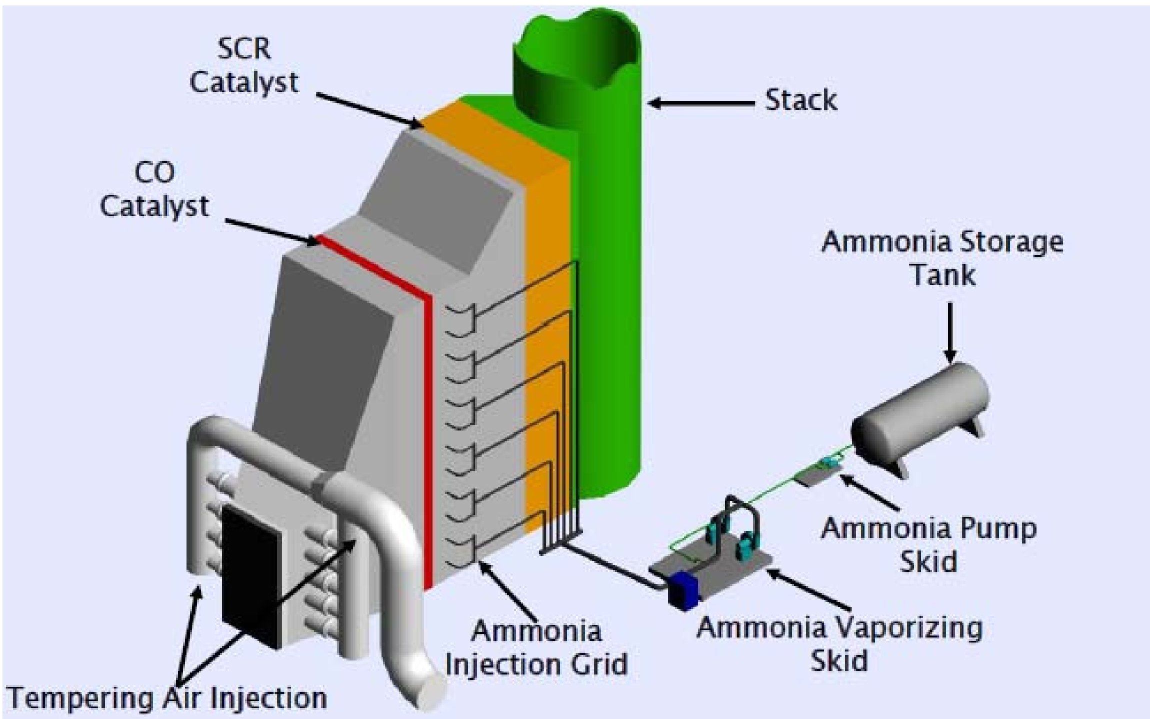
[19] Technical description adapted from EPA Air Pollution Control Technology Fact Sheet - FGD-Wet, Spray Dray, and Dry Scrubbers, as applicable to SABIC.

4.2.2.1 SCR[20]

SCR is an exhaust gas treatment process in which ammonia (NH_3) is injected into the exhaust gas upstream of a catalyst bed. On the catalyst surface, NH_3 and nitric oxide (NO) or nitrogen dioxide (NO_2) react to form diatomic nitrogen (N_2) and water (H_2O). The overall chemical reactions can be expressed as follows:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

Figure 4-2. SCR Basic Schematic Diagram



When operated within the optimum temperature range of 480 °F to 800 °F, the reaction can result in NO_X removal efficiencies between 70 and 90 percent. The rate of NO_X removal increases with temperature up to a maximum removal rate at a temperature between 700 °F and 750 °F. As the temperature increases to greater than the optimum temperature, the NO_X removal efficiency begins to decrease.

SCR is a technically feasible NO_X control technology for SABIC's COGEN.

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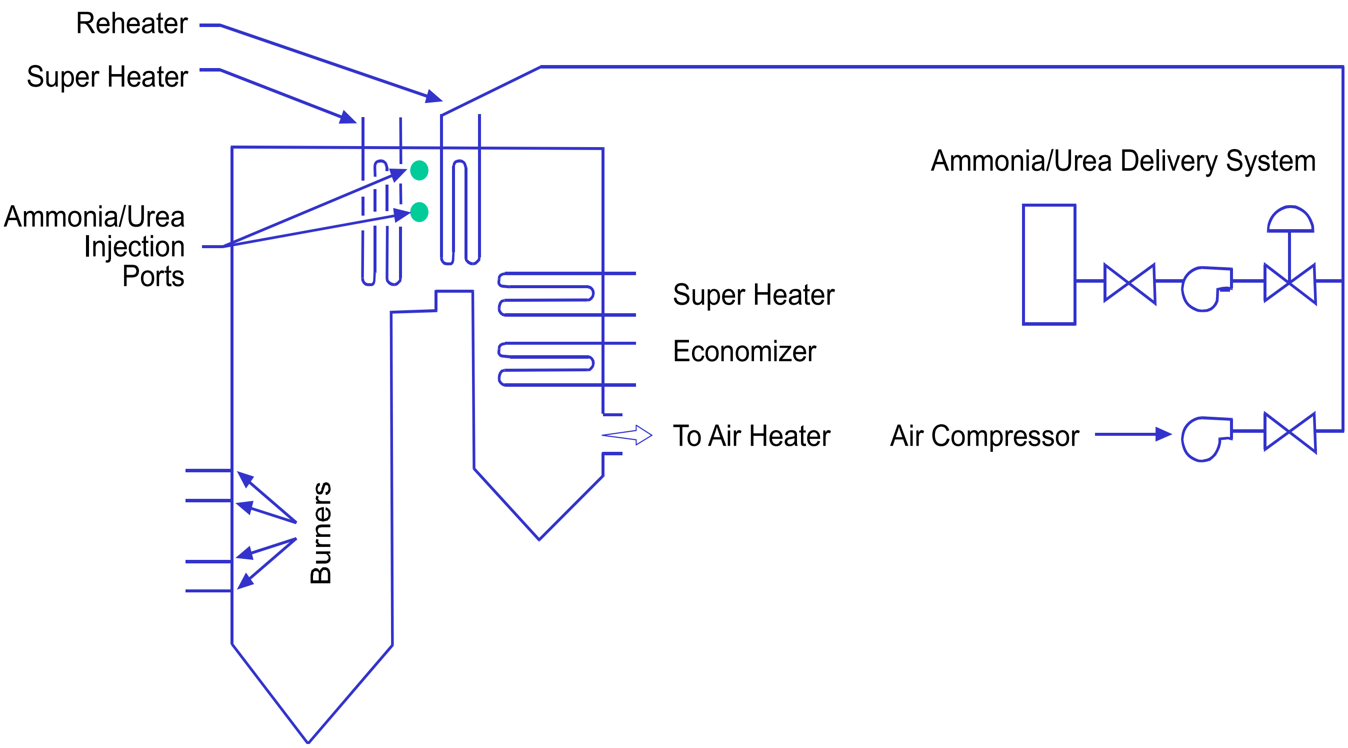
[20] Technical description adapted from EPA Air Pollution Cost Manual, Section 4.2, Chapter 2 Selective Catalytic Reduction, NO_X Controls, as applicable to SABIC.

4.2.2.2 SNCR[21]

The SNCR process reduces NO_x emissions using NH_3 or urea injection similar to SCR but operates only at higher temperatures. The overall chemical reactions can be expressed as follows:

$$2NO + 4NH_3 + 2O_2 \rightarrow 3N_2 + 6H_2O$$

Figure 4-3. SNCR Basic Schematic Diagram



NO_x reduction levels range from 30 to 50% for SNCR. The optimal temperature range is between 1600 °F and 2,200 °F at which NO_x is reduced to N_2 and water vapor. Since SNCR does not require a catalyst, it is more attractive than SCR from an economic standpoint, however, it is not compatible with gas turbine exhaust temperatures that do not exceed 1,100 °F. Because the exhaust temperature at the exit of the existing turbines, approximately 1,000 °F at the duct burner in SABIC's COGEN, is less than the optimum temperature range, approximately 1,625 °F for the application of this technology, it is not technically feasible to apply, and it is eliminated from further evaluation in this analysis.

4.2.2.3 SCONOx™ [22]

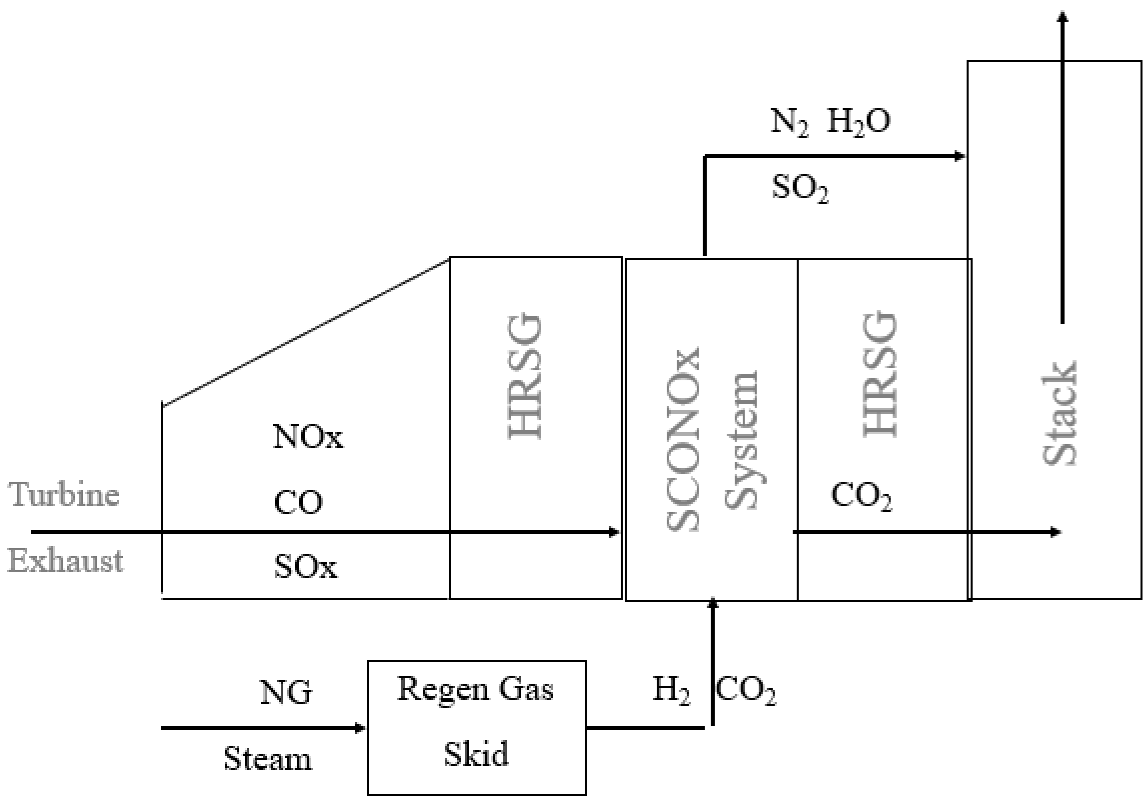
A relatively new post-combustion technology from EmeraChem is SCONO$_x$™, which utilizes a coated oxidation catalyst to remove both NO_x and CO without a reagent such as ammonia. SCONO$_x$™ has been primarily installed on co-generation or combined cycle systems where the exhaust gas temperature is

[21] Technical description adapted from EPA Air Pollution Cost Manual, Section 4.2, Chapter 1 Selective Non-Catalytic Reduction, NO_x Controls, as applicable to SABIC.

[22] Technical description adapted from National Energy Technology Laboratory https://netl.doe.gov/research/Coal/energy-systems/gasification/gasifipedia/nitrogen-oxides, as applicable to SABIC.

reduced by recovering energy to produce steam. The SCONO$_x$™ system catalyst is installed in the exhaust system at a point where the temperature is between 280 °F and 650 °F. Because the exhaust temperature at the exit of the existing turbines, approximately 1,000 °F, is greater than the optimum temperature range for the application of this technology, it is not technically feasible to apply SCONO$_x$™, and it is eliminated from further evaluation in this four-factor analysis.

Figure 4-4. SCONO$_x$™ General Schematic Diagram



5. FOUR-FACTOR ANALYSIS OF TECHNICALLY FEASIBLE SO_2 CONTROL OPTIONS

The technically feasible SO_2 control option of a packed-bed/tower scrubber to control emissions from the COS Vent Oxidizer, referred to as COS Vent Scrubber, is analyzed herein using the four statutory factors from Section 169A(g)(1) of the CAA.

5.1 Cost of Compliance (Statutory Factor 1)

5.1.1 Control Effectiveness

Table 5-1 summarizes the estimated control efficiency for a packed-bed wet scrubber, the only technically feasible add-on SO_2 emissions reduction options for COS Vent Oxidizer.

Table 5-1. Control Effectiveness of SO_2 Emissions Control Options

Source	SO_2 Control Option	Estimated Control Efficiency (%)
08-706 COS Vent Oxidizer	COS Vent Scrubber	95[a]

a. Engineering determination based on inlet loading SO_2 concentration and engineering knowledge of similar process applications.

5.1.2 Controlled Emissions

Table 5-2 summarizes the baseline and controlled emission rates and emission reduction potentials for the technically feasible SO_2 reduction option for the COS Vent Oxidizer.

Table 5-2. Baseline and Controlled Emission Rates of SO_2 Emissions Reduction Option

Source	Baseline Emission Rate [a] (tpy)	SO_2 Control Option	Controlled Emission Rate [a] (tpy)	Emissions Reduction (tpy)
COS Vent Oxidizer	570	COS Vent Scrubber	28	542

a. Based on 2018 actual emissions as submitted in SABIC's 2018 annual emissions inventory.

5.1.3 Cost

The following presents cost of compliance based on minimum estimated control efficiency of the add-on control option. An overall summary of estimated cost is presented in Table 5-3 with a detailed breakdown presented in Appendix A.

Table 5-3. Estimated Costs of SO_2 Emissions Reduction in 2019$

Source	SO_2 Control Option	Total Capital Investment ($)	Annual Cost ($/yr)	Cost Effectiveness ($/ton)
COS Vent Oxidizer	COS Vent Scrubber	$51,109,757	$6,213,119	$12,449

- As appropriate, SABIC used site-specific data and engineering judgement to refine the estimated costs summarized in Table 5-3. Appendix A contains additional details, references, and data sources for this SO_2 cost analysis.
- The Total Capital Investment (TCI) which includes a retrofit factor, uses cost data from a similar wet packed tower scrubber installation at MtV in 2010.
  - MtV's engineering and project management department records detailed the 2010 project included the absorber body/shell, packing, auxiliary equipment, instrumentation, sales taxes, and freight as well as direct installation costs (foundations, erection, piping, etc.) and indirect installation costs (engineering, start-up, etc.). [23]
  - The 2010 project did not include a quench chamber. This additional piece of equipment is assumed to be necessary between COS Vent Oxidizer outlet and the COS Vent Scrubber inlet. A quench chamber is deemed necessary to reduce the temperature of the COS Vent Oxidizer outlet to prevent damage (e.g., melting of scrubber packing) in the COS Vent Scrubber.
- The gas inlet flow rate from the 2010 scrubber project was ratioed with the anticipated COS Vent Scrubber gas inlet flow rate. SABIC used performance test data from the COS Vent Oxidizer (gas outlet flow rate from COS Vent Oxidizer is assumed to equal the inlet to a COS Vent Scrubber) to estimate the inlet gas flow rate for a COS Vent Scrubber.
- The Chemical Engineering Plant Cost Index (CEPCI)[24] was used to ratio the 2010 project cost to 2019 dollars.
- The factors provided in the EPA Air Pollution Control Cost Manual Section 5 Chapter 1 – Wet Scrubbers for Acid Gas for SO_2 were used to estimate the annual costs necessary to operate a packed tower scrubber.

A cost of over $12,000 per ton of SO_2 removed is too high to be economically feasible. SABIC did include discussion on the remaining three (3) statutory factors despite the installation of the COS Vent Scrubber being economically infeasible.

5.2 Time Necessary for Implementation (Statutory Factor 2)

The technically feasible SO_2 reduction option of a packed-bed wet scrubber, COS Vent Scrubber, for the CO generation process in the Phosgene process area would require substantial capital cost and detailed engineering design that is not included in this report. In addition, SABIC estimates that in order to secure additional funding (i.e., capital expenditure dollars) and engineering analysis/study for a wet scrubber

[23] EPA Air Pollution Control Cost Manual Section 5 SO_2 and Acid Gas Control, Chapter 1 Wet and Dry Scrubbers for Acid Gas Control, Table 1.7: Capital Cost Factors for Wet Packed Tower Absorbers, Public notice version issued July 2020.

[24] From https://www.chemengonline.com/pci-home accessed on February 10, 2020:

Year:	2010	2019
CEPCI:	550.8	607.5

system, would take 2 to 3 years if additional SO_2 control is required for regional haze visibility reasonable progress. If IDEM does not concur with SABIC's analysis that no control device is necessary after the COS Vent Oxidizer, SABIC requests additional time to provide further documentation and information to demonstrate that controls for this process operation are unnecessary.

Prior to implementation of any process design changes, including air pollution control projects, SABIC undergoes an independent and comprehensive engineering analysis. A typical schedule for such an engineering study is over a year.

A key metric within such an engineering study would be the impact the COS Vent Scrubber could have on the existing control device, COS Vent Oxidizer, or the process being controlled, CO generators and carbon adsorbers. The cost estimated for this four-factor analysis in Table 5-3 did not consider such impacts. It is possible that additional auxiliary equipment (e.g., blowers and ducting) could be necessary which would incur additional costs beyond those presented.

SABIC does not intend to investigate any add-on control device technologies to the COS Vent Oxidizer beyond what is discussed in this four-factor analysis.

5.3 Energy & Non-Air Quality Environmental Impacts (Statutory Factor 3)

The cost of energy required to operate the SO_2 control options is presented in the detailed cost analysis presented in Appendix A.

To operate control devices requiring greater power demand could decrease overall plant energy efficiency. At a minimum, the COS Vent Scrubber would require increased electrical usage by MtV which could create an increase in indirect (secondary) emissions from nearby power stations. Also, the Phosgene process area could need a new Motor Control Center for the various motors required to implement the wet scrubber control options.

Adverse environmental impacts are incurred for wet scrubbing in treating and disposing of large volumes of water from wet scrubber blowdown. SABIC's existing onsite wastewater treatment operations need to be consulted and involved in any alterations to MtV's wastewater facilities. The cost of wastewater treatment modifications is not analyzed in this report.

5.4 Remaining Useful Life (Statutory Factor 4)

The remaining useful life (RUL) of the CO generators in the Phosgene process area does not impact the annualized cost of an add-on control technology because the useful life is anticipated to be at least as long as the capital cost recovery period, which is 30 years. Similarly, the remaining useful life of the CO Generators does not impact the annualized cost for the control options that are evaluated.

5.5 SO_2 Emission Control Determination for Reasonable Progress

In consideration of all four factors required, SABIC has not identified any technically and economically feasible SO_2 control options for the COS Vent Oxidizer or COGEN at the MtV facility. Furthermore, there is no indication from VISTAS modeling that SABIC is causing significant impact on Class I areas as detailed in Section 3.3.

If IDEM does not agree with SABIC's conclusion that no additional SO_2 controls are necessary as part of this regional haze second implementation period, MtV requests additional time be given to undergo additional assessments (e.g., engineering studies, in-depth air dispersion modeling).

6. FOUR-FACTOR ANALYSIS OF TECHNICALLY FEASIBLE NO_X CONTROL OPTIONS

The technically feasible NO_X control option of a SCR is analyzed herein using the four statutory factors in Section 169A(g)(1) of the CAA.

6.1 Cost of Compliance (Statutory Factor 1)

6.1.1 Control Effectiveness

Table 6-1 summarizes the estimated control efficiency for a SCR to control NO_X emissions for COGEN, the only technically feasible add-on NO_X emissions reduction option.

Table 6-1. Control Effectiveness of SO_2 Emissions Control Options

Source	SO_2 Control Option	Estimated Control Efficiency (%)
19-001 COGEN	SCR	85[a]

a. Engineering determination based on internal design documents developed during COGEN installation.

6.1.2 Controlled Emissions

Table 6-2 summarizes the baseline and controlled emission rates and emission reduction potentials for the technically feasible SO_2 reduction options for COGEN.

Table 6-2. Baseline and Controlled Emission Rates of NO_X Emissions Reduction

Source	Baseline Emission Rate [a] (tpy)	NO_X Control Option	Controlled Emission Rate (tpy)	Emissions Reduction (tpy)
COGEN	119	SCR	17.8	101

a. Based on 2018 actual emissions as submitted in SABIC's 2018 annual emissions inventory.

6.1.3 Cost

The EPA Cost Manual for SCR[25] was used along with site-specific data inputs to estimate the cost of installing a SCR to control NO_X emissions from COGEN.

An overall summary of estimated cost is presented in Table 6-3 with a detailed breakdown presented in Appendix B.

[25] EPA Air Pollution Control Cost Manual Section 4 NO_X Controls Chapter 2-Selective Catalytic Reduction, June 2019.

Table 6-3. Estimated Costs (2019$) of NO_X Emissions Reduction

Source	NO_X Control Option	Total Capital Investment ($)	Annual Cost ($/yr)	Cost Effectiveness ($/ton)
COGEN	SCR	$21,805,180	$2,602,806	$25,691

SCR as a control technology to remove NO_X from COGEN emissions is achievable at an efficiency of 85 percent (%). The low concentration of NO_X in the COGEN exhaust leads to the high cost dollar per ton removal. The cost effectiveness per ton of NO_X removed is over $25,000 per ton, which is exorbitantly high. Installing a SCR to control NO_X emissions is not economically feasible for MtV.

6.2 Time Necessary for Implementation (Statutory Factor 2)

Installation of a SCR to reduce NO_X emissions from COGEN would require substantial capital and operating cost investments. A detailed design engineering project would need to be conducted, which in not included in the costs summarized in Table 6-3. Estimated Costs (2019$) of NO_X Emissions Reduction

SABIC estimates a total project length to install a SCR of 2 to 3 years including tasks such as, securing additional funding (i.e., capital expenditure dollars), completing a comprehensive engineering analysis and design studies.

SABIC does not intend to investigate any add-on control device technologies to COGEN beyond what is discussed in this four-factor analysis.

If IDEM does not concur with SABIC's analysis that no control device is necessary to reduce NO_X from COGEN, SABIC requests additional time to provide further documentation and information to confirm the unnecessariness of controls for this process operation.

6.3 Energy and Non-Air Environmental Impacts (Statutory Factor 3)

Potential energy and non-air environmental impacts of SCR include:

- Electric demand did not exist prior to installation.
- Creation of a new solid waste stream (spent catalyst).
- Storage of large amounts of liquid ammonia that may be regulated by EPA's risk management program (RMP) as accidental release of ammonia can cause serious injury.

Additionally, SCR operation can result in emissions of unreacted ammonia to the atmosphere (i.e., ammonia slip) during any periods of time when temperatures are too low for effective operation or if too much ammonia is injected. Ammonia emissions will react to directly form ammonium sulfate and ammonium nitrate. The amount of the potential visibility impact attributable to the use of ammonia in a SCR has not been quantified, but it would presumably negate some of the calculated visibility improvement that would otherwise be associated with the NO_X emission reductions.

As described in Section VISTAS Modeled Class I Impacts Outside LADCO RPO3.3, VISTAS CAMx modeling does not indicate any NO_X emissions, including those from COGEN, impact the visibility at Mammoth Cave.

6.4 Remaining Useful Life (Statutory Factor 4)

There are no enforceable limitations on the RUL for COGEN or any other units at MtV. However, the entire Co-generation facility was constructed in 2015 to 2016 and began full operation in fourth quarter 2016. For the purposes of this analysis, a 20-year RUL was used in the cost calculations summarized in Table 6-3. Estimated Costs (2019$) of NO_X Emissions Reduction and detailed in Appendix B.

6.5 NO_X Emission Control Determination for Reasonable Progress

The only technically feasible NO_X emissions reduction option, SCR, is not economically feasible based on this evaluation. Therefore, no additional NO_X controls are required for SABIC's COGEN unit during the regional haze second planning period. Furthermore, there is no indication from VISTAS modeling that NO_X emissions from SABIC are causing significant impact on Class I areas (Section 3.3).

7. RECOMMENDATIONS

In consideration of all four factors of the Regional Haze Program, SABIC has identified no reasonable NO_X or SO_2 control options for COGEN or COS Vent Oxidizer located at the MtV facility. Furthermore, there is no indication from photochemical modeling conducted by VISTAS that SABIC is causing a visibility impact on areas.

APPENDIX A. SO_2 COST ANALYSIS

Appendix A- SO_2 Control Effectiveness for Wet Packed Tower Gas Absorber (COS Vent Scrubber)

Capital Cost Summary

1	Preliminary Total Capital Investment (Prelim TCI)	PEC + DC + IC	$38,988,800	Table 1.7
2a	Estimated Direct and Indirect Costs (DC + IC)	Prelim. TCI / 2.17	$17,967,189	Equation 1.100
2b	Retrofit Cost	0.30 * (DC + IC)	$5,390,157	Section 1.2.4.3
1	Quench Chamber Cost		$1,960,556	
	Total Capital Investment (TCI) with Retrofit Cost Consideration and Quench Chamber		$46,339,513	
5	TCI as 2019 $		$51,109,757	

Annual Costs

Ref.	*Operation and Maintenance Costs*			*Table Ref.*
2a, 6	Operating Labor	0.5 hr/shift * 3 shifts/day * $/hr	$21,920	Table 1.8
2a, 6	Supervisor Labor	15% of operator labor	$3,288	Table 1.8
2a, 6	Maintenance Labor	0.5 hr/shift * 3 shifts/day * $/hr	$29,044	Table 1.8
2a	Maintenance Materials	100% of maintenance labor	$29,044	Table 1.8

Ref.	*Cost of Solvent/Reagent (Sodium Hydroxide NaOH)*		
3	Total Annual NaOH Usage	tons/yr	975
7	Unit cost	$/ton	$385.49
2a	Total	ton/yr * $/ton	$375,960

Ref.	*Cost of Wastewater Treatment*		
3	Discharge Blowdown	m^3/yr	31,122
3	Unit cost	$/$m^3$	$2.00
2a	Total	m^3/yr * $/$m^3$	$62,244

Ref.	*Auxiliary Power Costs*		
3	Power Required	kW	24
3	Hours Operated	t_{op}	6,340
8	Unit cost	$/kW-hr	$0.072
2a	Total	kW * $/kWh * t_{op}	$11,079

	Direct Annual Cost (DAC)	**$532,580**

Ref.	*Indirect Annual Cost*			*Table / Equation Ref.*
2a	Overhead	0.60 * Total Labor/Material $	$49,978	Table 1.8
2a	Administration Charges (AC)	0.02 * TCI	$1,022,195	Table 1.8
2a	Property Tax	0.01 * TCI	$511,098	Table 1.8
2a	Insurance	0.01 * TCI	$511,098	Table 1.8
2a, 4	Economic Life of Control Device	years	30	Table 1.8
2a, 4	Annual Interest Rate	%	7%	Table 1.8
2b	Capital Recovery Factor	CRF	0.0806	Equation 1.30
2a	Capital Recovery (CR)	CRF * TCI	$4,118,751	Table 1.8
	Indirect Annual Cost (IDAC)		**$6,213,119**	Table 1.8

Appendix A- SO_2 Control Effectiveness for Wet Packed Tower Gas Absorber (COS Vent Scrubber)

Cost Effectiveness Summary

Ref.	*Parameter*			*Table / Equation Ref.*
3	Baseline SO_2 Emissions	tons/yr	570	
3	Control Efficiency		95.0%	
3	Total SO_2 Removed	Baseline SO_2 * (1-Control Efficiency)	542	
2b	Total Annual Cost (2019 $)	TAC = IDAC + DAC	$6,745,699	Equation 1.31
2b	**Cost Effectiveness**	**$/ton removed**	**$12,449**	Equation 1.32

References:

1 TCI is derived using the cost for a similar wet packed tower gas absorber (i.e., scrubber) completed at MtV in 2010. MtV has assumed the 2010 project include the scrubber body, packing, auxiliary equipment, instrumentation, sales taxes, and freight as well as direct installation costs (foundations, erection, piping, etc.) and indirect installation costs (engineering, start-up, etc.).
Additionally, MtV provided an estimate for the TCI for a quench tower, which would be required prior to the scrubber to ensure proper operating conditions.
The gas inlet flow rate from the 2010 project was ratioed with the anticipated COS Vent Oxidizer Scrubber gas inlet flow rate. SABIC used stack test data from the COS Vent Oxidizer (gas outlet flow rate from COS Vent Oxidizer is assumed to equal the inlet to a COS Vent Oxidizer Scrubber) to estimate the inlet gas flow rate for a COS Vent Oxidizer Scrubber.

2 U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual* , Draft July 2020, Section 5, Chapter 1

2a Wet Packed Tower Gas Absorbers sub-section 1.3 of Section 5, Chapter 1
Table 1.7: Capital Cost Factors for Wet Packed Tower Absorbers
Table 1.8: Suggested Annual Cost Factors for Wet Packed Tower Absorbers
Section 1.3.3: Estimating Total Capital Investment: Equation 1.100

2b Wet Flue Gas Desulfurization sub-section of 1.2 of Section 5, Chapter 1
Section 1.2.4.3: Estimating Total Capital Investment
Section 1.2.4.4: Estimating Total Annual Cost for a Wet FGD System: Equations 1.30, 1.31, and 1.32

3 Data specific to SABIC's facility in Mt. Vernon, Indiana, such as estimations from engineering department and historic annual emission summary data.

4 Based on SABIC-specific estimated equipment lifetime and estimated bank interest rate.

5 Used Chemical Engineering Plant Cost Index, https://www.chemengonline.com/pci-home, accessed on February 10, 2020.

6 Hourly labor rates: Operating Labor $40/hr and Maintenance Labor $53/hr. These rates are representative of SABIC's current pay rates.

7 Reagent, sodium hydroxide NaOH, cost is an estimate from Echemi.com.

8 Electrical cost is an estimate from https://www.electricitylocal.com/states/indiana/mount-vernon/ .

APPENDIX B. NO_X COST ANALYSIS

Appendix B- NOX Control Cost Analysis for SCR on SABIC's COGEN
SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	1,812	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	15,485,970,732	scf/Year
Actual Annual fuel consumption (Mactual) =		12,643,340,488	scf/Year
Heat Rate Factor (HRF) =	NPHR/10 =	0.82	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.816	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	7,152	hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	85.0	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	28.33	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	101.3	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.06	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	818,037	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	110	/hour
Residence Time	$1/V_{space}$	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =	Not applicable; factor applies only to coal-fired boilers.	
Elevation Factor (ELEVF) =	14.7 psia/P =	1.06	
Atmospheric pressure at sea level (P) =	$2116 \times [(59-(0.00356xh)+459.7)/518.6]^{5.256} \times (1/144)$* =	13.9	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Appendix B- NOX Control Cost Analysis for SCR on SABIC's COGEN

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	7,437.61	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	852	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	980	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	31.3	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	53	feet

Appendix B- NOX Control Cost Analysis for SCR on SABIC's COGEN

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	11	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	38	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	5	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	1,800	gallons (storage needed to store a 14 day reagent supply rounded to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 =	0.0837
	Where n = Equipment Life and i= Interest Rate	

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ =	931.72	kW
	where A = (0.1 x QB) for industrial boilers.		

Appendix B- NOX Control Cost Analysis for SCR on SABIC's COGEN
Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$21,805,180	in 2019 dollars

Appendix B- NOX Control Cost Analysis for SCR on SABIC's COGEN

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$773,776	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,829,030	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$2,602,806	in 2019 dollars

Direct Annual Costs (DAC)

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

Annual Maintenance Cost =	0.005 x TCI =	$109,026	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$10,628	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$476,453	in 2019 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$177,669	in 2019 dollars
Direct Annual Cost =		$773,776	in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$3,936	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,825,094	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,829,030	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$2,602,806	per year in 2019 dollars
NOx Removed =	101	tons/year
Cost Effectiveness =	$25,691	per ton of NOx removed in 2019 dollars

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Appendix H

Alcoa Four-Factor Analysis Submittal

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September 25, 2020

Thomas Shaw, PhD
Senior Environmental Scientist
Alcoa Warrick Operations
4400 W. State Route 66
Newburgh, IN 47629

Re: Final Draft Report
Four-Factor Analysis requested by IDEM
Alcoa Warrick Operations

Dear Dr. Shaw:

In a letter dated June 24, 2020, Indiana Department of Environmental Management (IDEM) requested Alcoa complete a Four-Factor Analysis for sulfur dioxide (SO_2) emissions to assist IDEM in revising its State Implementation Plan (SIP) for the Regional Haze Rule. Information regarding SO_2 emissions control on Potlines 2 through 6 and the Anode Baking Ring Furnace was requested. IDEM has advised the four statutory factors to be evaluated for the potlines and ring furnace include the following:

1. The cost of compliance
2. The time necessary to achieve compliance
3. The energy and non-air quality environmental impact of compliance
4. The remaining life of any existing source subject to such requirements

Alcoa Warrick Operations (Alcoa) retained Burns & McDonnell to assist in responding to the request for information from IDEM. The letter report summarizes the results of the Four-Factor Analysis.

<u>Factor 1: Cost of Compliance</u>

In July 2007, Babcock Power Environmental (Babcock Power) provided Alcoa a budgetary proposal for a Flue Gas Desulfurization (FGD) system for the control of SO_2 emissions from Potlines 2 through 6. To estimate the capital cost of installing an FGD system to control SO_2 emissions from the potlines, Burns & McDonnell updated the budgetary cost in this proposal by escalating to reflect inflation from 2007 to 2020. An annual inflation rate of 2.5% was assumed over this time period based on information from the Chemical Engineering Plant Cost Index (CEPCI).

Burns & McDonnell developed a rough order-of-magnitude cost estimate for installing SO_2 controls on the Anode Baking Ring Furnace and associated A-446 Dry Alumina Scrubbers based on the escalated Babcock Power budgetary proposal. The budgetary cost estimate for the FGD for the potlines was scaled to represent an FGD system for the Anode Baking Ring Furnace based on the flue gas parameters provided by Alcoa.

Babcock Power's budgetary proposal included equipment costs only. Burns & McDonnell added rough order-of-magnitude construction costs based on an industry-standard multiplier of direct equipment costs.

Operating and Maintenance (O&M) costs for an FGD system include reagent (lime) usage, waste disposal, power usage, water usage, operating labor, and maintenance labor and materials. Based on

Burns & McDonnell's past project experience, FGD system O&M costs can range from $3,800,000/year to $14,500,000/year, based on the flue gas and SO_2 loading to the FGD system.

Burns & McDonnell developed rough order-of-magnitude O&M cost estimates for FGD systems on the potlines and Anode Baking Ring Furnace based on information provided in Babcock Power's budgetary proposal for reagent, water and power usage and waste generated.

The capital and annual O&M cost estimates for a new FGD system on the potlines and the Anode Baking Ring Furnace are summarized in Table 1. Note all costs are in 2020 dollars and represent rough order-of-magnitude costs.

Table 1. FGD System Cost Estimate Summary

Scrubber	Capital	Annual O&M
Potline 2 through 6	$512,800,000	$5,300,000
Anode Baking Ring Furnace	$63,900,000	$700,000
Total	$576,700,000	$6,000,000

Factor 2: Time Needed to Achieve Compliance

A new FGD system typically requires 30 to 36 months for front end planning, design, procurement, installation and commissioning. Alcoa's capital planning process would add 12 to 18 months to this timeframe. Additional time may be needed for technology selection and environmental permitting. Note that space constraints and access limitations at the Alcoa site could result in an extended design and installation period.

Factor 3: Energy and Environmental Impacts of Compliance

FGD technologies are energy intensive. Depending on the FGD technology selected, large pumps may be needed to recycle the reagent slurry through the FGD module. The retrofit of an FGD system on an existing emission source also may require an additional fan or fans to overcome the pressure drop of the FGD module(s). These pumps and/or fans can significantly increase the energy consumption of the Alcoa facility. Auxiliary electric power is also required to operate reagent preparation systems, reagent injection equipment, and waste byproduct handling systems.

FGD systems also create solid byproducts and may have a wastewater stream, depending on the FGD technology selected. Both the disposal of the solid byproduct and the discharge of the wastewater stream may have additional impact on the environment. The synthetic gypsum market has excess inventory and undesirable pricing; therefore, the solid FGD byproduct will need to be disposed of in a landfill.

The delivery of FGD system reagent and disposal of the associated solid byproduct will increase vehicle traffic and the associated particulate matter emissions on site. The storage and handling of the reagent and byproduct also will increase particulate matter emissions from the facility. Some FGD technologies are based on chemical reactions that create carbon dioxide (CO_2), a greenhouse gas and regulated pollutant.

Factor 4: Remaining Life of the Existing Sources

The Alcoa potlines have been in operation since 1960, and Alcoa continues to maintain them for continuous, reliable operation. The Anode Baking Ring Furnace was constructed in 1981 and rebuilt in 2008. The remaining life of each of the production units is based on economic factors and product demand, and therefore cannot be predicted at this time.

Please feel free to contact Karen Burchardt at 816-509-3400 should you have any questions or require additional information regarding this report.

Respectfully submitted,

Karen E. Burchardt

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