INDIANA

REGIONAL HAZE

STATE IMPLEMENTATION PLAN

FOR THE

SECOND IMPLEMENTATION PERIOD

Nitrogen Oxides and Sulfur Dioxide
Four-Factor Analysis
For
Iron and Steel Mills, Aluminum Production and Plastics Manufacturing Plants and Electric Services Plant

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acfm	Actual Cubic Feet Per Minute
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BFG	Blast Furnace Gas
BOF	Basic Oxygen Furnace
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
$CaSO_3$	Calcium Sulfate
$CaSO_4$	Calcium Sulfate
CEMS	Continuous Emissions Monitoring System
CEPCI	Chemical Engineering Plant Cost Index
CFR	Code of Federal Regulations
Cl_2	Chlorine
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COGEN	Co-generation Unit
COS	Carbonyl Sulfide
CS_2	Carbon Disulfide
CSAPR	Cross State Air Pollution Rule
CWPB1	Center-Worked Prebake One
DSI	Dry Sorbent Injection
EGU	Electric Generating Unit
EPA	United States Environmental Protection Agency
ETS	Emission Tracking System
FGD	Flue Gas Desulfurization
FIP	Federal Implementation Plan
FLMs	Federal Land Managers
FR	Federal Register
GHG	Greenhouse Gas
GTC	Gas Treatment Center
HRSGs	Heat Recovery Steam Generators
H_2S	Hydrogen Sulfide
HCI	Hydrochloric Acid
ID	Induced Draft
IDEM	Indiana Department of Environmental Management
LADCO	Lake Michigan Air Directors Consortium
LAER	Lowest Achievable Emission Rate
lb/MMscf	Pound Per Million Standard Cubic Foot
lb/MMBtu	Pound Per Million British Thermal Units
LNB	Low-NO_x Burners
NAAQS	National Ambient Air Quality Standards
NaOH	Sodium Hydroxide
NESHAPs	National Emission Standards for Hazardous Air Pollutants
NG	Natural Gas

NH_3	Ammonia
NO.	Number
NO_x	Nitrogen Oxides
NSPS	New Source Performance Standards
MMBTU	Million British Thermal Unit
MMBTU/hr	Million British Thermal Unit Per Hour
PM	Particulate Matter
ppm	Parts Per Million
PSD	Prevention of Significant Deterioration
RACT	Reasonably Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
RFI	Request for Information
RH	Regional Haze
RPGs	Reasonable Progress Goals
scf	Standard Cubic Foot
SCR	Selective Catalytic Reduction
SDA	Spray Dryer Absorber
SIP	State Implementation Plan
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
STG	Steam Turbine Generator
tons/yr	Tons Per Year
ULNB	Ultra-Low-NO_x Burners
VOC	Volatile Organic Compound
WBF	Walking Beam Furnace

1.0 INTRODUCTION

The Regional Haze (RH) Rule requires each state to develop a long-term strategy that includes the control measures necessary to make reasonable progress at each Class I area outside the state "that may be affected by emissions from the state." The Clean Air Act (CAA) and RH Rule provides for states to determine what emission control measures for its own sources, groups of sources, and/or source categories are necessary to make reasonable progress in Class I areas. Section 169A(g)(1) of the CAA lists four factors that must be taken into consideration in determining reasonable progress. Potential pollution control technologies available to achieve reasonable progress goals (RPGs) are evaluated with respect to the four factors listed below:

- Cost,
- Compliance timeframe,
- Energy and non-air quality environmental impacts, and
- Remaining useful life for affected sources.

The "four-factor" analysis conducted in this document includes identifying which nitrogen oxides (NO_x) and sulfur dioxide (SO_2) emission control measures to consider, evaluating the four factors to be characterized for the NO_x and SO_2 control options considered, and evaluating the cost effectiveness of the emission control measures identified for the facilities selected in accordance with the Code of Federal Regulations (CFR), 40 CFR 51.308(f)(2) of the RH Rule. This four-factor analysis will also include selecting NO_x and SO_2 emissions information for characterizing emissions-related factors and identifying applicable Federal regulations that contribute NO_x and SO_2 emission control benefits in reducing regional haze by 2028 and beyond.

2.0 BACKGROUND

The emissions inventory and contribution assessment performed by the Lake Michigan Air Directors Consortium (LADCO) for member states, Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin demonstrated that NO_x and SO_2 emissions were key contributors to visibility impairment at Class I areas in the Northern Midwest region. In Indiana, seven sources from the iron and steel mill manufacturing, aluminum production, and plastics manufacturing sectors met the Indiana Department of Environmental Management's (IDEM's) source selection criteria for the RH SIP second implementation period four-factor analysis.

IDEM sent a request for information (RFI) to the owners/operators of the selected sources requesting that the companies submit a four-factor analysis for the highest emitting NO_x and SO_2 emission units at each selected source. The emission units identified for NO_x and/or SO_2 four-factor evaluation were chosen based on the units' reported 2018 NO_x and SO_2 emissions. IDEM compared the emission units reported 2018 NO_x and SO_2 emissions to the units' NO_x and SO_2 potential to emit calculations to ensure the values were not substantially different due to reduced operating hours, then selected the emission units at each source found to be the highest NO_x and SO_2 emitters. No specific cutoff value or percentage was used to identify a facility's highest NO_x

and SO_2 emitting units. The information provided in this document was obtained from the four-factor analysis submittals received for each facility to be evaluated for four-factor analysis.

This document combines the four-factor analyses companies submitted for the emission units identified by IDEM and includes the justification for emission units for which a four-factor analysis evaluation was not conducted; however, the visibility analyses included in the companies' submittals are not included in this document. The visibility analyses for the four-factor analysis selected sources will be included in the next step in the SIP development process, "Decisions on What Control Measures are Necessary to Make Reasonable Progress," Step 5, in the United States Environmental Protection Agency's (EPA's), "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, Page 28" and discussed in the body of Indiana's RH SIP document. The four-factor analysis submittals from which most of the information provided in this document was obtained are attached as appendices for reference.

3.0 IRON AND STEEL MILL PLANTS

The approach used by Cleveland-Cliffs Steel - Indiana Harbor East (Indiana Harbor East), Cleveland-Cliffs Steel - Indiana Harbor West (Indiana Harbor West), Cleveland-Cliffs Burns Harbor, LLC (Burns Harbor), and United States Steel Corporation - Gary Works, (Gary Works), to identify emission control measures for the emission units and pollutants identified by IDEM for analysis is described below. 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. For technically feasible emission control measures that were identified; Indiana Harbor East, Indiana Harbor West, Burns Harbor, Gary Works and evaluated each emission control measure against the four statutory factors listed in Section 1 of this document. 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 were not considered as part of these analyses.

Instead, these evaluations focus on commercially demonstrated control options on similar sources at integrated iron and steel mills. For purposes of this analysis, the steel mills selected for four-factor analysis evaluated only those emission control measures that have the potential to achieve an overall pollutant emissions reduction greater than the performance of the existing systems. The following tasks were completed to develop a reasonable set of emission control measures to be considered against the four statutory factors evaluation:

1. Reviewed the EPA 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 many sources was provided in the BACT evaluation for Nucor Steel Louisiana "Consolidated Environmental Management Inc - Nucor Steel Louisiana, Best Available Control Technology Analyses," March 1, 2010 (Nucor 2010

BACT). A summary of the RBLC data reviewed is provided in Appendix A of the four-factor analysis documents submitted by the owners/operators of the selected sources as Appendices to this document for reference.

2. Reviewed the air permits for other iron and steel mills to identify emission control measures and emission limits, which are being used in practice; a comparison of air permits from similar iron and steel mills is provided in Appendix B of the four-factor analysis documents submitted by the owners/operators of the selected sources as Appendices to this document for reference.

3. Reviewed the Nucor 2010 BACT analysis, which provides additional detail regarding specific control technologies that were evaluated for technical feasibility.

4. Selected 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 of emission control measures 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 Nucor 2010 BACT.

3.1 Cleveland-Cliffs Steel - Indiana Harbor East (Indiana Harbor East) NO_x and SO_2 Emissions and Controls

Cleveland-Cliffs Steel operates as a contractor at the Cleveland-Cliffs Indiana Harbor Works (CC-IH), facility in East Chicago, Indiana. The Cleveland-Cliffs Indiana Harbor Works facility operations includes the primary operation, Indianan Harbor East (Plant ID 089-00316), an integrated steel mill, located at, 3210 Watling Street, East Chicago, Indiana, and the secondary operation, Indiana Harbor West (Source ID 089-00318), 3001 Dickey Road, East Chicago, Indiana, collocated with a number of other on-site contractors.

Indiana Harbor East is an integrated steel mill located in East Chicago, Indiana. Operations include raw material handling, sintering, ironmaking, steelmaking, and manufacturing of hot-rolled and cold-rolled products, as well as on-site utility generation. The six emission unit groups IDEM identified in the RFI are listed in the table below; the sources of NO_x and/or SO_2 emissions and existing control measures for each emission unit chosen for four-factor analysis evaluations are described in this section.

Table 3-1 Indiana Harbor East Emission Units and Pollutants Identified for Four-Factor Analysis

Emission Unit	Applicable Pollutant(s)
No. 4 Basic Oxygen Furnace	NO_x
No. 5 Boiler House Boilers 501-504	NO_x, SO_2
No. 7 Blast Furnace Stoves, Casthouse and Flare	NO_x, SO_2
Lime Plant Nos. 1 and 2 Preheater and Rotary Kilns	NO_x, SO_2
80” Hot Strip Mill Walking Beam Furnaces #4-#6	NO_x
Sinter Plant Windbox	NO_x, SO_2

No. 4 Basic Oxygen Furnace

The No. 4 Basic Oxygen Furnace (BOF) charges molten iron from the blast furnaces, flux, alloys, and scrap with high-purity oxygen. This process oxidizes or removes excess carbon, silicon, manganese, and other impurities from the hot metal to produce molten steel. When the temperature and composition are satisfactory, the molten steel is tapped into a transfer ladle for subsequent processing. The BOF off-gas is routed to a wet scrubber. NO_x emissions are generated from atmospheric nitrogen in proximity with the combustion of carbon upon contact with the high-purity oxygen injection. These emissions are assumed to be primarily thermal NO_x.

No. 5 Boiler House Boilers 501, 502, 503, and 504

The No. 5 Boiler House Boilers 501-504 produce utility steam for operating turbo-blowers in the generation of cold blast (wind) to the blast furnace, high pressure steam for power generation at the turbine, and low-pressure steam for use throughout the Indiana Harbor East facility. Each boiler predominantly fires blast furnace gas (BFG) and automatically supplements natural gas (NG) to maintain BFG header pressure. Additionally, NG is occasionally used for flame stability during periods of blast furnace startup/shutdown/low heating value.

The No. 5 Boiler House Boilers 501-504 generate NO_x emissions from NG and BFG combustion. BFG is considered a low-NO_x fuel because it has a lower heating value compared to NG (approximately 10% of the heating value) which creates a lower flame temperature and generates significantly less thermal NO_x. The No. 5 Boiler House Boilers 501-504 utilize low-NO_x fuel and good combustion practices as NO_x emission control measures.

SO_2 emissions generated by the No. 5 Boiler House Boilers 501-504 are from NG and BFG combustion. NG and BFG are considered low-sulfur fuels when compared to other solid and liquid fuels and are utilized as an SO_2 emission control measure.

No. 7 Blast Furnace Stoves, Casthouse and Flare

The No. 7 Blast Furnace combines 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 BFG and supplemental NG to heat fresh air for injection. BFG is the partially combusted, carbon monoxide (CO)-rich gas that is produced within the blast furnace itself. This gas has a low heating value compared to NG which creates a lower flame temperature and generates significantly less thermal NO_x. BFG is then cleaned for particulate matter (PM) via the integrated scrubbing system prior to combustion as a fuel source to offset purchased fuels and improve energy efficiency. A flare combusts excess BFG that is not utilized by the downstream units. 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).

NO_x emissions from the No. 7 Blast Furnace Stoves are primarily generated from firing BFG and enriched oxygen (with occasional NG enrichment) 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. BFG is considered a low-NO_x fuel because it has a lower heating value compared to NG, a lower flame temperature and generates significantly less thermal NO_x. Therefore, the use of BFG in the No. 7 Blast Furnace Stoves is an existing NO_x emission control measure.

The No. 7 Blast Furnace Stoves generate SO_2 emissions through oxidation of sulfur compounds present in the fuel (BFG and NG). BFG and NG are considered low-sulfur fuels, compared to other solid and liquid fuels, and are utilized as SO_2 emission control measures.

NO_x emissions from the No. 7 Blast Furnace Casthouse may be generated during the casting process and are a result of reactions of nitrogen in ambient air. In a similar reaction, the No. 7 Blast Furnace Casthouse's 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 fugitive-in-nature (i.e., not emitted from a stack).

The No. 7 Blast Furnace Flares produce NO_x and SO_2 due to the combustion of blast furnace waste gas and a NG pilot. BFG is a low-NO_x fuel and is utilized as an existing NO_x emission control measure. In addition, BFG and NG are considered low-sulfur fuels and are utilized as SO_2 emission control measures.

<u>Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns</u>
The No. 1 and No. 2 Lime Plants produce lime for use throughout the facility. Lime is produced through thermal decomposition of limestone in rotary kilns, where calcium carbonate decomposes into calcium oxide and waste carbon dioxide at temperatures in excess of 1800ºF. The kilns are fired with NG or residual fuel oil.

The Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns generate NO_x emissions from NG and fuel oil combustion. The preheater utilizes residual heat from the rotary kiln combustion gases to preheat limestone feed, which increases energy efficiency. This increased energy efficiency results in less fuel usage, and less NO_x emissions as a result. Therefore, the use of a preheater is considered a NO_x emission control measure for Lime Plant No. 1 and No. 2.

The Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns generate SO_2 emissions from NG and fuel oil combustion. NG is the primary fuel source and is considered a low-sulfur fuel, compared to other solid and liquid fuels, and is utilized as a SO_2 emission control measure for these unit. The use of a preheater to preheat limestone feed using residual heat in combustion gases reduces NG SO_2 emissions by reducing fuel requirements. Furthermore, the production of lime that is in contact with combustion gases inherently scrubs combustion gases of SO_2, further reducing SO_2 emissions from the unit.

80” Hot Strip Mill Walking Beam Furnaces #4, #5, and #6
The 80” Hot Strip Mill Walking Beam Furnaces (WBFs) #4-#6 heat incoming steel slabs to working temperatures for downstream mill operations. The reheat furnaces fire NG only and the combustion gases are in direct contact with the steel slabs.

The 80” Hot Strip Mill WBFs #4-#6 generate NO_x emissions from NG combustion and follow good combustion practices as a NO_x emission control measure. In addition, the #4 WBF is equipped with ultra-low-NO_x burners (ULNB) to control NO_x emissions. Induced flue gas recirculation burners, also referred to as ULNB, combine the principles of flue gas recirculation and low-NO_x burner control technologies. The burner draws flue gas to dilute the fuel and utilize staged fuel combustion to reduce the flame temperature and thermal NO_x formation.

Sinter Plant Windbox
The Sinter Plant Windbox agglomerates iron ore fines and other recycled materials from various sources to create a raw material feedstock for the blast furnaces. The sinter feedstocks are blended together (called burden), the surface is ignited within a furnace, and the solid fuel in the blend is combusted by drawing air through the bed of material, sintering the material together while the combustion products are pulled into the windboxes. The windboxes exhaust to a multiclone and baghouse to control PM emissions. Sintered material is then cooled, sized, and screened.

Along the traveling grate, the iron ore fines, coke breeze, and other recycled material fines are ignited with NG burners. The NO_x emissions are generated from the associated combustion of the solid fuels in the sinter burden and NG. The Sinter Plant Windbox follows good combustion practices as a NO_x emission control measure.

The Sinter Plant Windbox generates SO_2 emissions through oxidation of sulfur compounds present in the raw materials (iron byproduct/recycled materials, coke breeze, etc.) and NG fuel. As an SO_2 emission control measure, Indiana Harbor East conducts routine material sampling and adjusts the Sinter Plant Windbox feed blend to comply with the source’s Title V Operating Permit SO_2 limit.

3.1.1 Indiana Harbor East Four-Factor Analysis of Potential NO_x Control Options

This section describes the rationale Cleveland-Cliffs Steel used to determine the reasonable set of NO_x emission control measures for the emission units IDEM selected for four-factor analysis at the Indiana Harbor East facility.

No. 4 Basic Oxygen Furnace
The RBLC search and search of air permits for iron and steel mills and similar sources with BOFs did not identify any NO_x emission control measures for the four-factor analysis evaluation. The RBLC search found that no additional NO_x emission control measures were required for a 2005 BACT determination for the Wheeling Pittsburgh Steel Corporation (RBLCID = OH-0292) (Wheeling Pittsburgh 2005 BACT). As such,

the No. 4 BOF has no reasonable set of NO_x emission control measures beyond what is currently installed and operated for this emission unit.

No. 5 Boiler House Boilers 501-504

The RBLC search and search of air permits for iron and steel mills and similar sources for boilers NO_x emission control measures identified the use of low-NO_x fuel, selective catalytic reduction (SCR), low-NO_x burners (LNB), and ULNB at some sources. The No. 5 Boiler House Boilers 501-504 already utilize low-NO_x fuel combustion (BFG) and good combustion practices as existing NO_x emission control measures.

The RBLC search listed many references to the installation of SCR, LNB, and ULNB for NG-only-fired boilers. However, the No. 5 Boiler House Boilers 501-504 are not directly comparable to boilers that strictly fire NG because the No. 5 Boiler House Boilers 501-504 fire BFG (a low-NO_x fuel) and supplements with NG to maintain flame temperature.

SCR was excluded from the reasonable set of NO_x emission control measures because it has not been installed and successfully operated on a similar source under similar physical and operating conditions (i.e., BFG as a primary fuel source). LNB were addressed in the Briefing Sheet accompanying the Nucor 2010 Permit to Construct [Prevention of Significant Deterioration (PSD)-LA-740] (Nucor 2010 PSD Permit to Construct), which stated that LNB was eliminated as technically infeasible for the following rationale: "LNB limit the formation of NO_x by staging the addition of air to create a longer, cooler flame. The combustion of BFG in the top gas boilers requires the supplement of NG in order to maintain flame stability and prevent flameouts of the burners. The use of LNB would attempt to stage fuel gas at the limits of combustibility and potentially prevent combustion of the fuel from occurring. Thus, LNB were not a feasible control technology for the top gas boilers."

LNB, and by extension ULNB which uses the same principles (longer, cooler flame), represent a negligible or potentially small emission reduction potential, compared to the current NO_x emission control measures, and have potential operational challenges, therefore, LNB and ULNB were not considered as part of the reasonable set of NO_x emission control measures for the No. 5 Boiler House Boilers 501-504 and were not evaluated further in Cleveland-Cliffs' analysis.

There are no additional NO_x emission control measures based on the emission control measures described in the RBLC and air permits for iron and steel mills. As such, the No. 5 Boiler House Boilers 501-504 have no reasonable set of NO_x emission control measures beyond what is currently installed and operated for these emission units.

No. 7 Blast Furnace Stoves, Casthouse and Flare

The RBLC search and search of air permits for iron and steel mills and similar sources for blast furnace stove NO_x emission control measures identified the use of low-NO_x fuel or LNB at some sources. The No. 7 Blast Furnace Stoves already utilize low-NO_x fuel combustion (BFG) as an existing NO_x emission control measure.

SCR was excluded from the reasonable set because it has not been installed and successfully operated on a similar source under similar physical and operating conditions when BFG is used as a primary fuel source. However, the AK Steel Dearborn B and C Furnaces installed LNB as part of a 2014 PSD Permit (AK Steel Dearborn 2014 PSD Permit). It is not clear nonetheless that LNB offer any additional emission reduction potential compared to the existing NO_x emission control measures (BFG - low-NO_x fuel). EPA stated the following in a document titled "Alternative Control Techniques Document -- NO_x Emissions from Iron and Steel Mills," 1994, Page 5-22 (Alternative Control Techniques Document) "…the primary fuel is BFG, which is largely CO, has a low heating value, and contains inerts, factors that reduce flame temperature. Thus, the NO_x concentration in blast furnace stove flue gas tends to be low and the potential for NO_x reduction is considered to be small."

LNB were eliminated as technically infeasible because they limit the formation of NO_x by staging the addition of air to create a longer, cooler flame according to the Nucor 2010 PSD Permit to Construct Briefing Sheet. The combustion of BFG in the top-gas boilers requires the supplement of NG in order to maintain flame stability and prevent flameouts of the burners. Using the rational discussed previously, the use of LNB would attempt to stage fuel gas at the limits of combustibility and potentially prevent combustion of the fuel from occurring. Thus, LNB are not a feasible control technology for the top-gas boilers. And as previously stated, LNB and by extension ULNB which uses the same principles (longer, cooler flame), represent a negligible or potentially small emission reduction potential, compared to the current NO_x emission control measures, and have potential operational challenges. Therefore, LNB and ULNB are not considered as part of the reasonable set of NO_x emission control measures for the No. 7 Blast Furnace Stoves and are not evaluated further in this analysis.

The RBLC search and search of air permits for iron and steel mills and similar sources for No. 7 Blast Furnace Casthouse did not identify any NO_x emission control measures. The Nucor 2010 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. Therefore, there are no additional NO_x emission control measures based on the emission control measures described in the RBLC and air permits for iron and steel mills and the No. 7 Blast Furnace Casthouse has no reasonable set of NO_x emission control measures beyond what is currently installed and operated for this emission unit.

There are also no additional NO_x emission control measures based on the emission control measures described in the RBLC and air permits for iron and steel mills for the No. 7 Blast Furnace Flare. As such, the No. 7 Blast Furnace Flare has no reasonable set of NO_x emission control measures beyond what is currently installed and operated for this emission unit.

Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns

The RBLC search and search of air permits for iron and steel mills and similar sources for lime plant NO_x emission control measures identified the use of LNB or kiln preheaters at some sources. Preheaters are an existing NO_x emission control measure for Lime Plant No. 1 and No. 2. Based on the air permit review, there are no other iron and steel mills that have on-site lime plants.

Indiana Harbor East identified LNB to be part of the potentially feasible NO_x emission control measures for further evaluation. However, the iron and steel mill industry consulted with a burner manufacturer who stated that a low-NO_x burner for burning only NG was available but co-firing oil with NG presents additional design concerns and they could not guarantee an emission reduction for this technology. Additionally, EPA stated the following in the EPA, "New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting," October 1990, Page B.13. (New Source Review Workshop Manual) "Historically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives." Therefore, LNB were not further considered because eliminating oil as an allowable fuel would fundamentally redefine the source and there was no guaranteed emission reduction with a co-fired burner.

There are no additional NO_x emission control measures based on the emission control measures described in the RBLC and air permits for lime kilns, as such the Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns have no reasonable set of NO_x emission control measures beyond what is currently installed and operated for these emission units.

80" Hot Strip Mill WBF #4, #5, and #6

The RBLC search and search of air permits for iron and steel mills and similar sources for walking beam furnace NO_x emission control measures identified the use of SCR or LNB/ULNB at some sources. The 80" Hot Strip Mill WBFs #4-#6 implement good combustion practices, and the #4 WBF has LNB as existing NO_x emission control measures.

The RBLC search listed references to installations of SCR, LNB, ULNB, and no controls required. There is one instance of SCR for NO_x emission control, a reheat furnace at Thyssenkrupp Steel and Stainless USA, LLC (Thyssenkrupp) (RBLC ID: AL-0230). The Thyssenkrupp 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 Indiana Harbor East. Therefore, SCR is not part of a reasonable set of NO_x emission control measures for the 80" Hot Strip Mill WBFs #4-#6.

Since 80" Hot Strip Mill WBF #4 already has ULNB installed, there are no additional NO_x emission control measures based on the emission control measures described in the RBLC and air permits for iron and steel mills. As such, the 80" Hot Strip Mill WBF #4 has no reasonable set of NO_x emission control measures beyond what is currently installed and operated for these emission units. However, Indiana Harbor East identified LNB/ULNB to be part of the reasonable set of NO_x emission control measures for further evaluation for the 80” Hot Strip Mill WBFs #5 and #6.

Sinter Plant Windbox

The Sinter Plant Windbox utilizes good combustion practices as a NO_x emission control measure. The RBLC search and search of air permits for iron and steel mills and similar sources for sinter plant windboxes did not identify any NO_x emission control measures. As such, the Sinter Plant Windbox has no reasonable set of NO_x emission control measures beyond what is currently installed and operated for this emission unit.

Table 3-2 Indiana Harbor East Emission Units NO_x Control Technologies Analyzed or Justification for No Analysis

Emission Unit	Control Technologies Analyzed	Justification for No Analysis
No. 4 Basic Oxygen Furnace	None	There are no reasonable NO_x emission control measures beyond what is currently installed and operated.
No. 5 Boiler House Boiler 501-504	None	There are no reasonable NO_x emission control measures beyond what is currently installed and operated.
No. 7 Blast Furnace Stoves, Casthouse and Flare	None	There are no reasonable NO_x emission control measures beyond what is currently installed and operated.
Lime Plant Nos. 1 and 2 Preheater and Rotary Kiln	None	There are no reasonable NO_x emission control measures beyond what is currently installed and operated.
80” Hot Strip Mill WBF #4	None	There are no reasonable NO_x emission control measures beyond what is currently installed and operated.
80” Hot Strip Mill WBF #5 and #6	LNB/ULNB	
Sinter Plant Windbox	None	There are no reasonable NO_x emission control measures beyond what is currently installed and operated.

3.1.1.1 Cost of Compliance for Potential NO_x Control Options

The results of Cleveland-Cliffs’ evaluation of potential NO_x control measures identified low-NO_x burners LNB/ULNB for the 80” Hot Strip Mill WBFs #5 and #6. Therefore, the four-factor analysis in this section will evaluate LNB/ULNB for the walking beam furnaces.

Cleveland-Cliffs completed cost estimates for LNB/ULNB installation on the 80" Hot Strip Mill WBFs #5 and #6. Cost summary spreadsheets for the NO_x emission control measures are provided in Appendix A. The cost-effectiveness analysis compares the annualized cost of the emission control measure per ton of pollutant removed and is evaluated on a dollar per ton basis using the annual cost (annualized capital cost plus annual operating costs) divided by the annual emissions reduction (tons) achieved by the control device. For purposes of this screening evaluation and consistent with the typical approach described in the EPA Control Cost Manual, a 20-year life (before new and extensive capital is needed to maintain and repair the equipment) at 5.5% interest is assumed in annualizing capital costs.

3.1.1.2 Time Necessary for Potential NO_x Control Options 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 Indiana Harbor East's Title V operating permit to allow construction to commence, then time 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.

These 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). If a rulemaking for the site-specific SIP limit is necessary, then this process could take even longer.

3.1.1.3 Energy and Non-Air Impacts of Potential NO_x Control Options

LNB/ULNB installation on the 80" Hot Strip Mill WBFs #5 and #6 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/ULNB are negligible for this analysis.

3.1.1.4 Remaining Useful Life of Potential NO_x Control Options

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

3.1.2 NO_x Emissions Trends at the Indiana Harbor East Facility

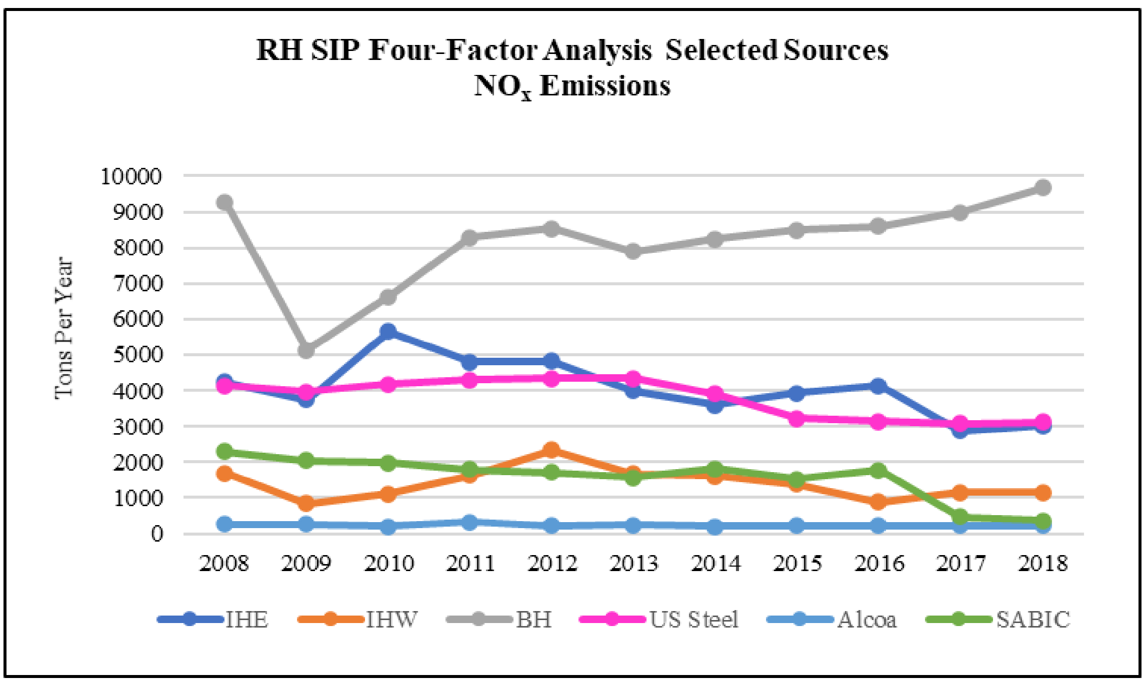
Indiana Harbor East facility-wide NO_x emissions show a downward trend over the 11-year evaluation period as reflected in Table 3-3 and Graph 3-1 on the next page with a significant decrease in NO_x emissions in 2009 due to an economic downturn that resulted in reduced production rates during that year; then ratcheted back up to the highest NO_x emission level over the 11-year period peak in 2010. The line graph in Graph 3-1 illustrates an overall 29% decrease in facility-wide NO_x emissions from 2008 to 2018 as a result of shut down operations, which included two blast furnaces, one AC station, one electric arc furnace, and one ladle metallurgical operation.

Table 3-3 Indiana Selected Sources 2008-2018 NO_x Emissions

Year	IHE	IHW	BH	Gary Works	Cokenergy	SABIC	Alcoa
2008	4243.72	1694.60	9283.27	4136.80	---	2288.61	263.18
2009	3753.32	841.04	5128.28	3984.94	---	2043.12	257.63
2010	5663.79	1109.51	6626.21	4190.44	---	1990.15	208.51
2011	4812.73	1635.24	8289.26	4313.47	---	1798.92	331.59
2012	4831.54	2327.01	8546.69	4341.45	---	1724.97	221.66
2013	3996.08	1667.23	7898.55	4356.99	---	1570.77	237.66
2014	3607.72	1620.79	8254.31	3920.69	---	1809.72	202.73
2015	3932.03	1388.67	8491.62	3235.59	---	1536.66	232.23
2016	4131.64	892.66	8599.48	3142.94	---	1784.16	214.41
2017	2868.45	1149.23	9000.89	3089.13	---	464.64	217.58
2018	3023.44	1152.53	9685.64	3118.63	---	374.38	228.50

Note: emissions information obtained from the Environmental Protection Agency's National Emissions Inventory Database.

Graph 3-1 Indiana Selected Sources 2008-2018 NO_x Emissions Trends



3.1.3 Indiana Harbor East Reasonable Level of Control for NO_x Emissions

ULNB technology was determined to be the reasonable NO_x emission control measure to reduce NO_x emissions, beyond what is currently installed and operated, from the 80" Hot Strip Mill WBFs. The associated NO_x cost-effectiveness values ($ per ton of emissions reduction) for the addition of ULNB technology to control NO_x emissions are $9,300 per ton of NO_x removed for WBF #5 and $7,000 per ton of NO_x removed for WBF #6 as shown in the Cost Effectiveness and Cost Estimate spreadsheets in Appendix A.

3.1.4 Indiana Harbor East Four-Factor Analysis of Potential SO_2 Control Options

<u>No. 5 Boiler House Boilers 501, 502, 503, and 504</u>

The RBLC search and search of air permits for iron and steel mills and similar sources for boiler SO_2 emission control measures identified the use of low-sulfur fuels at some sources. The No. 5 Boiler House Boilers 501-504 already utilize low-sulfur fuel combustion (NG and BFG) as an existing SO_2 emission control measure and there are no additional SO_2 emission control measures beyond what is currently installed and operated for these emission units based on the emission control measures described in the Nucor 2010 BACT, the RBLC, and air permits for iron and steel mills. As such, the No. 5 Boiler House Boilers 501-504 have no reasonable set of SO_2 emission control measures beyond what is currently installed and operated.

<u>No. 7 Blast Furnace Stoves, Casthouse, and Flare</u>

The RBLC search and search of air permits for iron and steel mills and similar sources for blast furnace stove, casthouse, and flare SO_2 emission control measures identified the use of low-sulfur fuel at one source. The No. 7 Blast Furnace Stoves, Casthouse, and Flare already routinely fire low sulfur fuels (BFG and NG) as an existing SO_2 emission control measure. The AK Steel 2014 Dearborn BACT concluded that additional SO_2 emission control measures for Blast Furnace Stoves and Casthouses were not required and the Nucor 2010 BACT determined that other than the low-sulfur fuels (BFG and NG), no additional add-on SO_2 emission control measures are technically feasible for blast furnace stoves, casthouses, and flares.

Therefore, there are no additional SO_2 emission control measures for blast furnace stoves, casthouses, and flares according to the RBLC and air permits for iron and steel mills. As such, the No. 7 Blast Furnace Stoves, Casthouse, and Flare have no reasonable set of SO_2 emission control measures beyond what is currently installed and operated for these emission units.

<u>Lime Plant No. 1 and No. 2</u>

The RBLC search and search of air permits for iron and steel mills and similar sources for lime plant SO_2 emission control measures identified the use of a fuel sulfur limit or dry scrubbing by lime production at some sources. The Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns utilize low-sulfur fuel combustion (NG), preheaters to reduce fuel usage, and inherent lime scrubbing during production as existing SO_2 emission control measures.

Based on the air permit review conducted, there are no other iron and steel mills that have on-site lime plants. A coal or petroleum coke fuel sulfur limit is not appropriate in this application because the Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns fuel sources (NG and residual oil) generate less SO_2 emissions compared to solid fuel sources (coal and petroleum coke) according to EPA's "AP-42," Section 11, February 1998.

A sulfur limit for fuel is not considered in the reasonable set of SO_2 emission control measures. So, there are no additional SO_2 emission control measures based on the emission control measures described in the RBLC and air permits for iron and steel mills. As such, the Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns have no reasonable set of SO_2 emission control measures beyond what is currently installed and operated for these emission units.

Sinter Plant Windbox

The Sinter Plant utilizes routine material sampling and sinter feed management as an SO_2 emission control measure. The RBLC search and search of air permits for iron and steel mills and similar sources for Sinter Plant SO_2 emission control measures identified the use of wet scrubbing, spray dryer absorber (SDA) installation, and/or dry sorbent injection (DSI). SDA systems spray lime slurry into an absorption tower where SO_2 is absorbed by the slurry, forming $CaSO_3$/$CaSO_4$. The liquid-to-gas ratio is such that the water evaporates before the droplets reach the bottom of the tower. The dry solids are collected with a fabric filter downstream. Dry sorbent (pulverized lime or limestone) is directly injected into the duct upstream of a fabric filter. SO_2 reacts with the sorbent, and the solid particles are collected by the fabric filter. Further SO_2 removal occurs as the flue gas flows through the filter cake on the bags.

The Sinter Plant Windbox is already controlled for PM, a visibility impairing pollutant, using baghouses. A wet scrubber system may result in unacceptable increases to PM because the existing baghouse (dry controls) would need to be removed for compatibility issues (e.g., wetting the bag) associated with a wet scrubber system. Furthermore, the SO_2 that is captured by the scrubber would need to be neutralized and treated as wastewater. Since the associated issues are not present and the SO_2 emission control performance is generally comparable with SDAs or DSI (dry controls), wet scrubbing was excluded from the reasonable set of SO_2 emission control measures. SDAs installation and DSI for the Sinter Plant Windbox are evaluated as SO_2 emission control measures.

Table 3-4 Indiana Harbor East Emission Units SO_2 Control Technologies Analyzed or Justification for No Analysis

Emission Unit	Control Technologies Analyzed	No Analysis Justification
No. 5 Boiler House Boiler 501-504	None	There are no reasonable SO_2 emission control measures beyond what is currently installed and operated.
No. 7 Blast Furnace Stoves, Casthouse and Flare	None	There are no reasonable SO_2 emission control measures beyond what is currently installed and operated.
Lime Plant Nos. 1 and 2 Preheater and Rotary Kiln	None	There are no reasonable SO_2 emission control measures beyond what is currently installed and operated.
Sinter Plant Windbox	Spray Dryer Absorber and DSI	

3.1.4.1 Cost of Compliance for Potential SO_2 Control Options

Indiana Harbor East completed cost estimates for spray dryer installation and DSI on the Sinter Plant Windbox. Cost summary spreadsheets for the SO_2 emission control measures are provided in Appendix A. The cost-effectiveness analysis compares the annualized cost of the emission control measure per ton of pollutant removed and is evaluated on a dollar per ton basis using the annual cost (annualized capital cost plus annual operating costs) divided by the annual emissions reduction (tons) achieved by the control device. For purposes of this screening evaluation and consistent with the typical approach described in the EPA Control Cost Manual, a 20-year life (before new and extensive capital is needed to maintain and repair the equipment) at 5.5% interest is assumed in annualizing capital costs.

The installation of DSI or a SDA would require significant modifications to the current pollution control train. The existing baghouse is unable to accommodate additional particulate loading. Therefore, a new baghouse would be required for both emission control measures, capable of capturing process and sorbent dust. In addition, new controls cannot be installed while the plant is operating. Plot space surrounding the Sinter Plant is very limited and it is not feasible to construct a new baghouse without blocking vehicle and truck traffic required to operate the process. Therefore, the Sinter Plant would need to be shut down for a minimum of 4-6 months to demolish the current controls and install DSI or a SDA. This would result in a large lost production cost to the facility, which is not accounted for in the control costs, and is not economically feasible for Indiana Harbor East.

To account for the limited space around existing equipment, a 50 percent markup of the total capital investment (i.e., a 1.5 retrofit factor) was included in the costs to account for the installation. Retrofit installations have increased handling and erection difficulty for many reasons. Access for transportation, laydown space, etc. for new equipment is significantly impeded or restricted. As noted above, the spaces surrounding the Sinter Plant are congested, and the areas surrounding the Sinter Plant support frequent vehicle traffic or crane access for maintenance and cannot be used for material staging. Additionally, the emission control measures evaluated in this section are complex and increase the associated installation costs (e.g., ancillary equipment requirements, piping, structural, electrical, demolition, etc.). Finally, the EPA Control Cost Manual notes that retrofit installations are subjective because the plant designers may not have had the foresight to include additional floor space and room between components for new equipment. Retrofits impose additional costs to "shoehorn" equipment in existing plant space, which is true for the Sinter Plant. The resulting cost-effectiveness calculations are summarized in Appendix A.

3.1.4.2 Time Necessary for Potential SO_2 Control Options 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 emission limit into the SIP by state and federal action, time for IDEM to modify Indiana Harbor East's Title V operating permit to allow construction to commence, then time 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.

These 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. If a rulemaking for the site-specific SIP limit is necessary, then this process could take even longer.

3.1.4.3 Energy and Non-Air Impacts of Potential SO_2 Control Options

The SDA and DSI would increase energy usage due to the higher pressure drop across absorber vessel (SDA only) and the downstream baghouse, material preparation such as grinding reagents, additional material handling equipment such as pumps and blowers, and steam requirements. Power consumption is also affected by the reagent utilization, which also affects the associated control efficiency. As a minimum, this would require increased electrical usage by the plant with associated increase indirect (secondary) emissions from nearby power stations. The new process gas duct burners will consume additional fuel to evaporate spray dryer moisture.

The cost of energy required to operate the SDA and DSI have been included in the cost analysis found in Appendix A. The SDA and DSI would generate additional solid waste that would require disposal in permitted landfills.

3.1.4.4 Remaining Useful Life for SO_2 Control Options

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

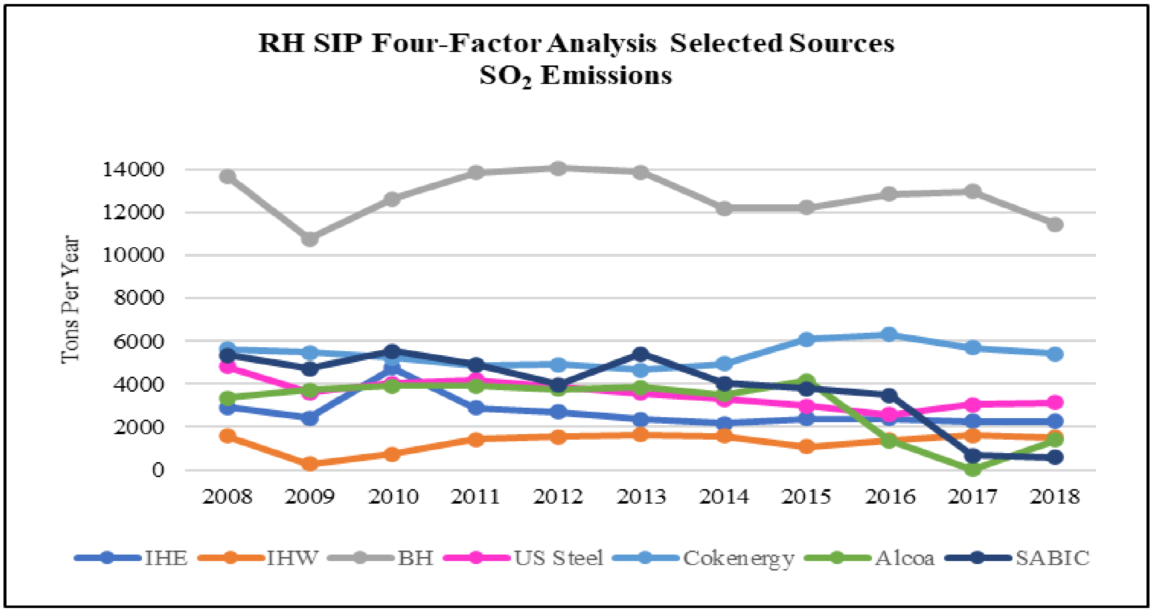
3.1.5 SO_2 Emissions Trends at the Indiana Harbor East Facility

Indiana Harbor East facility-wide SO_2 emissions listed in Table 3-5 below and shown in Graph 3-2 on the following page show the same downward trend over the 11-year evaluation period. As described in Section 3.1.2 and illustrated on the line graph in Graph 3-2 on the next page, there was a significant decrease in SO_2 emissions in 2009 due to an economic downturn that resulted in reduced production rates during the year. The overall SO_2 emissions from the facility decreased 23% from 2008 to 2018.

Table 3-5 Indiana Four-Factor Analysis Selected Sources 2008-2018 SO_2 Emissions

Year	IHE	IHW	BH	Gary Works	Cokenergy	SABIC	Alcoa
2008	2905.00	1569.26	13692.81	4801.82	5621.70	5340.53	3362.48
2009	2412.59	281.51	10763.97	3600.26	5475.18	4725.81	3728.50
2010	4758.34	726.00	12620.01	4030.33	5214.00	5515.96	3899.26
2011	2873.83	1432.03	13842.76	4201.76	4891.50	4915.55	3897.81
2012	2684.50	1538.89	14052.34	3854.41	4904.06	3982.91	3747.94
2013	2369.13	1637.69	13863.97	3563.74	4653.25	5406.67	3852.49
2014	2162.82	1587.39	12189.46	3285.02	4951.50	4029.74	3500.48
2015	2397.75	1067.42	12202.18	2980.11	6103.20	3782.81	4146.61
2016	2391.71	1387.49	12830.72	2589.65	6298.00	3469.27	1373.60
2017	2273.63	1618.73	12959.40	3029.74	5681.00	680.03	24.00
2018	2248.79	1511.68	11452.05	3149.65	5398.00	591.24	1397.38

Graph 3-2 Indiana Selected Sources 2008-2018 SO_2 Emissions Trends



3.1.6 Indiana Harbor East Reasonable Level of Control for SO_2 Emissions

The reasonable set of SO_2 emission control measures beyond what is currently installed and operated for the Sinter Plant Windbox consists of SDAs and DSI systems. The associated cost-effectiveness values ($ per ton of emissions reduction) for the SDAs and DSI control measures are $28,904 per ton of SO_2 removed for the SDA and $38,200 per ton of SO_2 removed for the DSI system. The Cost Effectiveness and Cost Estimate spreadsheets are attached in Appendix A.

3.2 Cleveland-Cliffs Steel - Indiana Harbor West (Indiana Harbor West) NO_x and SO_2 Emissions and Controls

Indiana Harbor West is an integrated steel mill located in East Chicago, Indiana. Operations include raw material handling, ironmaking, steelmaking, and manufacturing of hot-rolled, and hot-dipped galvanized sheet products, as well as on-site utility generation. The three emission unit groups selected for NO_x and/or SO_2 four-factor analyses in IDEM's RFI are listed in the table below and the sources of each unit's NO_x and SO_2 emissions and existing control measures are described in this section.

Table 3-6 Indiana Harbor West Emission Units and Pollutants Identified for Four-Factor Analysis

Emission Unit	Applicable Pollutant(s)
Basic Oxygen Furnaces	NO_x
Boiler House #8 Boiler (S8G)	NO_x, SO_2
H-3 and H-4 Blast Furnace Stoves, Casthouses and Flares	NO_x, SO_2

Basic Oxygen Furnaces

The BOFs at Indiana Harbor West facility charge molten iron from the blast furnaces, flux, alloys, and scrap with high-purity oxygen. This process oxidizes or removes excess carbon, silicon, manganese, and other impurities from the hot metal to produce molten steel. When the temperature and composition are satisfactory, the molten steel is tapped into a transfer ladle for subsequent processing. Off-gas resulting from the basic oxygen process are controlled with an electrostatic precipitator for PM control. NO_x emissions are generated from atmospheric nitrogen in proximity with the combustion of carbon upon contact with the high-purity oxygen injection. These emissions are assumed to be primarily thermal NO_x.

Boiler House - #8 Boiler (S8G)

The Boiler House - #8 Boiler (S8G) produces utility steam for operating turbo-blowers in the generation of cold blast (wind) to the blast furnace(s), high pressure steam for power generation at the turbine, and low-pressure steam for use throughout the Indiana Harbor West facility. The boiler predominantly fires BFG and supplements NG to maintain fuel header pressure and flame stability during periods of blast furnace startup/shutdown.

The Boiler House - #8 Boiler (S8G) generates NO_x emissions from NG and BFG combustion. BFG is considered a low-NO_x fuel because it has a lower heating value compared to NG which creates a lower flame temperature and generates significantly less thermal NO_x as previously discussed. The Boiler House - #8 Boiler (S8G) utilizes low-NO_x fuel and good combustion practices as NO_x emission control measures.

The Boiler House - #8 Boiler (S8G) generates SO_2 emissions from NG and BFG combustion. NG and BFG are considered low-sulfur fuels when compared to other solid and liquid fuels and are utilized as an SO_2 emission control measure.

H-3 and H-4 Blast Furnaces Stoves, Casthouses and Flares

The H-3 and H-4 Blast Furnaces 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 BFG and supplemental NG to heat fresh air for injection. BFG 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. 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 H-3 and H-4 Blast Furnace Stoves resulting NO_x emissions are generated from primarily firing BFG and NG 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 cold blast for recovering heat back to the furnace through "hot blast" injection. Again, BFG is considered a low-NO_x fuel because it has a lower heating value compared to NG which creates a lower flame temperature and generates significantly less thermal NO_x. Therefore, the use of BFG in the H-3 and H-4 Blast Furnace Stoves is an existing NO_x emission control measure.

The H-3 and H-4 Blast Furnace Stoves generate SO_2 emissions through oxidation of sulfur compounds present in the fuel (BFG and NG). BFG and NG 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 H-3 and H-4 Blast Furnace Casthouses may be generated during the casting process and are a result of reactions of nitrogen in ambient air. The H-3 and H-4 Blast Furnace Casthouses' molten iron and slag streams contain sulfur compounds that oxidize to form SO_2 upon contact with ambient air during the casting process. For the H-4 Blast Furnace, taphole drilling/plugging and iron ladle filling emissions are collected and routed to the H-4 casthouse baghouse for particulate control. Emissions from slag runners and pits are either uncaptured or outside of the casthouse and fugitive-in-nature.

The H-3 and H-4 Blast Furnace Flares produce NO_x and SO_2 due to the combustion of blast furnace waste gas and NG pilots. BFG is a low-NO_x fuel and is utilized as an existing NO_x emission control measure. Both BFG and NG are considered low-sulfur fuels and are utilized as SO_2 emission control measures.

3.2.1 Indiana Harbor West Four-Factor Analysis of Potential NO_x Control Options

Basic Oxygen Furnaces

The RBLC search and search of air permits for iron and steel mills and similar sources for basic oxygen furnaces did not identify any NO_x emission control measures. The RBLC search found that no additional NO_x emission control measures were required for the Wheeling Pittsburgh 2005 BACT determination. Therefore, there are no additional NO_x emission control measures based on the emission control measures described in the RBLC and air permits for iron and steel mills. As such, the BOFs have no reasonable set of NO_x emission control measures beyond what is currently installed and operated for these emission units.

Boiler House - #8 Boiler (S8G)

The RBLC search and search of air permits for iron and steel mills and similar sources for boiler NO_x emission control measures identified the use of low-NO_x fuel, SCR, LNB, and/or ULNB at some sources. The Boiler House - #8 Boiler (S8G) already utilizes low-NO_x fuel combustion (BFG) and good combustion practices as existing NO_x emission control measures.

The RBLC search listed many references to the installation of SCR, LNB, and ULNB for NG-only-fired boilers. However, the Boiler House - #8 Boiler (S8G) is not directly comparable to boilers that strictly fire NG because the Boiler House - #8 Boiler (S8G) fires BFG and supplements with NG to maintain flame temperature.

SCR was excluded from the reasonable set because it has not been installed and successfully operated on a similar source under similar physical and operating conditions when BFG is used as a primary fuel source as previously mentioned. LNB were eliminated as technically infeasible because they limit the formation of NO_x by staging the addition of air to create a longer, cooler flame. The combustion of BFG in the top-gas boilers requires the supplement of NG in order to maintain flame stability and prevent flameouts of the burners. Using the rationale previously discussed, the use of LNB would attempt to stage fuel gas at the limits of combustibility and potentially prevent combustion of the fuel from occurring. Thus, LNB are not a feasible control technology for the top-gas boilers. In addition, LNB and by extension ULNB which uses the same principles, represent a negligible or potentially small emission reduction potential, compared to the current NO_x emission control measures, and have potential operational challenges. Therefore, LNB and ULNB are not considered as part of the reasonable set of NO_x emission control measures for the Boiler House - #8 Boiler (S8G) and are not evaluated further in this analysis.

There are no additional NO_x emission control measures based on the emission control measures described in the RBLC and air permits for iron and steel mills. As such, Boiler House - #8 Boiler (S8G) has no reasonable set of NO_x emission control measures beyond what is currently installed and operated for this emission unit.

H-3 and H-4 Blast Furnaces Stoves, Casthouses and Flares

The RBLC search and search of air permits for iron and steel mills and similar sources for blast furnace stoves NO_x emission control measures identified the use of low-NO_x fuel or LNB at some sources. The H-3 and H-4 Blast Furnace Stoves already utilize low-NOx fuel combustion (BFG) as an existing NO_x emission control measure.

As part of the AK Steel Dearborn 2014 PSD Permit, B and C Furnaces have LNB installed; however, it is not clear that LNB offer any additional emission reduction potential compared to the existing NO_x emission control measures because the primary fuel is BFG, which is largely CO, has a low heating value, and contains inerts, factors that reduce flame temperature, as previously discussed. Thus, the NO_x concentration in blast furnace stove flue gas tends to be low and the potential for NO_x reduction is considered to be small.

Additionally, LNB was eliminated as technically infeasible because LNB limit the formation of NO_x by staging the addition of air to create a longer, cooler flame. Again, the combustion of BFG in the hot blast stoves requires the supplement of a small amount of NG in order to maintain flame stability and prevent flameouts of the burners. The use of LNB would attempt to stage fuel gas at the limits of combustibility and would prevent the operation of the hot blast stoves. Thus, LNB are not a feasible control technology for the hot blast stoves.

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 the H-3 and H-4 Blast Furnace Stoves. Therefore, the H-3 and H-4 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 Nucor 2010 BACT, emission control measures described in the RBLC and air permits for similar sources and are not evaluated further in this analysis.

Table 3-7 Indiana Harbor West Emission Units NO_x Control Technologies Analyzed or Justification for No Analysis

Emission Unit	Control Technologies Analyzed	No Analysis Justification
Basic Oxygen Furnaces	None	There are no reasonable NO_x emission control measures beyond what is currently installed and operated.
Boiler House - #8 Boiler (S8G)	None	There are no reasonable NO_x emission control measures beyond what is currently installed and operated.
H-3 and H-4 Blast Furnace Stoves, Casthouses and Flares	None	There are no reasonable NO_x emission control measures beyond what is currently installed and operated.

3.2.2 NO_x Emissions Trends at the Indiana Harbor West Facility

The Indiana Harbor West facility-wide NO_x emissions show a downward trend from 2008 to 2018 as reflected in Table 3-3 on page 12. The line graph shown in Graph 3-1 on page 12 illustrates a decrease in facility-wide NO_x emissions in 2009 then emissions ratcheted back up to the highest-level facility-wide NO_x emissions over the 11-year period in 2012. Indiana Harbor West has achieved an overall 32% decrease in facility-wide NO_x emission reductions over the 11-year evaluation period as a result of shut down operations, including the No. 2 Sinter Plant and 84" Hot Strip Mill Reheat Furnaces 1, 2, and 3, and eliminated oil burning capability on facility boilers.

3.2.3 Indiana Harbor West Reasonable Level of Control for NO_x Emissions

The evaluation for NO_x emission control measures determined that there are no reasonable NO_x emission control measures beyond what is currently installed and operated for the emission units identified; therefore, no cost effectiveness analysis was conducted.

3.2.4 Indiana Harbor West Four-Factor Analysis of Potential SO_2 Control Options

Boiler House - #8 Boiler (S8G)

The RBLC search and search of air permits for iron and steel mills and similar sources for boiler SO_2 emission control measures identified the use of low-sulfur fuels at some sources. The Boiler House - #8 Boiler (S8G) already utilizes low-sulfur fuel combustion (NG and BFG) as an existing SO_2 emission control measure.

There are no additional SO_2 emission control measures based on the emission control measures described in the Nucor 2010 BACT, the RBLC, and air permits for iron and steel mills. Therefore, the Boiler House - #8 Boiler (S8G) has no reasonable set of SO_2 emission control measures beyond what is currently installed and operated.

H-3 and H-4 Blast Furnaces Stoves, Casthouses, and Flares
The RBLC search and search of air permits for iron and steel mills and similar sources for blast furnace stove SO_2 emission control measures identified the use of low-sulfur fuel at one source. The H-3 and H-4 Blast Furnace Stoves routinely fire low-sulfur fuels (BFG and NG) an existing SO_2 emission control measure. The AK Steel Dearborn 2014 PSD Permit did not require additional SO_2 emission control measures and the Nucor 2010 BACT determined that other than the low-sulfur fuels (BFG and NG), no additional add-on SO_2 emission control measures are technically feasible.

Therefore, there are no additional SO_2 emission control measures based on the Nucor 2010 BACT, emission control measures described in the RBLC and air permits for iron and steel mills. As such, the H-3 and H-4 Blast Furnace Stoves have no reasonable set of SO_2 emission control measures beyond what is currently installed and operated for these emission units.

The RBLC search and search of air permits for iron and steel mills and similar sources for blast furnace casthouses did not identify any SO_2 emission control measures, either. The AK Steel Dearborn 2014 PSD Permit did not require additional SO_2 emission control measures and the Nucor 2010 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.

Therefore, there are no additional SO_2 emission control measures based on the Nucor 2010 BACT, emission control measures described in the RBLC, and air permits for iron and steel mills. As such, the H-3, and H-4 Blast Furnace Casthouses have no reasonable set of SO_2 emission control measures beyond what is currently installed and operated for these emission units.

The RBLC search and search of air permits for iron and steel mills and similar sources for blast furnace flares did not identify any SO_2 emission control measures. Therefore, there are no additional SO_2 emission control measures based on the Nucor 2010 BACT, emission control measures described in the RBLC, and air permits for iron and steel mills. As such, the H-3 and H-4 Blast Furnace Flares have no reasonable set of SO_2 emission control measures beyond what is currently installed and operated for these emission units.

Table 3-8 Indiana Harbor West Emission Units SO_2 Control Technologies Analyzed or Justification for No Analysis

Emission Unit	Control Technologies Analyzed	No Analysis Justification
Boiler House - #8 Boiler (S8G)	None	There are no reasonable SO_2 emission control measures beyond what is currently installed and operated.
H-3 and H-4 Blast Furnace Stoves, Casthouses and Flares	None	There are no reasonable SO_2 emission control measures beyond what is currently installed and operated.

3.2.5 SO_2 Emissions Trends at the Indiana Harbor West Facility

Indiana Harbor West have achieved some facility-wide SO_2 emission reductions from 2008 to 2018 as a result of shutdown operations, including the No. 2 Sinter Plant and 84” Hot Strip Mill Reheat Furnaces 1, 2, and 3, and the elimination of oil burning capability on facility boilers. The line graph in Graph 3-2 on page 18 show a decrease in facility wide SO_2 emissions in 2009 due to an economic downturn that resulted in reduced production rates. Indiana Harbor West reduced SO_2 emissions by 16% over the 11-year evaluation period according to Table 3-5 on page 17.

3.2.6 Indiana Harbor West Reasonable Level of Control for SO_2 Emissions

The evaluation for SO_2 emission control measures determined that there are no reasonable SO_2 emission control measures beyond what is currently installed and operated for the emission units identified; therefore, no cost effectiveness analysis was conducted.

3.3 Cleveland-Cliffs Burns Harbor, LLC (Burns Harbor) NO_x and SO_2 Emissions and Controls

Burns Harbor 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 four emission unit groups identified in IDEM’s RFI are listed in Table 3-9 on the next page and the sources of each unit’s NO_x and SO_2 emissions and existing control measures are described in this section.

Table 3-9 Burns Harbor Emission Units and Pollutants Identified for Four-Factor Analysis

Emission Unit	Applicable Pollutant(s)
Battery Nos. 1 and 2	NO_x, SO_2
Clean Coke Oven Gas Export Line and Flare*	NO_x, SO_2
Power Station Boiler Nos. 7-12	NO_x, SO_2
Blast Furnaces C and D	NO_x, SO_2

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

Battery Nos. 1 and 2

Coke-making 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 BFG, while Battery No. 2 fires coke oven gas to heat the coal and 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 BFG and coke oven gas under-fire combustion. BFG is considered a low-NO_x fuel because it has a lower heating value compared to NG which creates a lower flame temperature and generates significantly less thermal NO_x, as previously mentioned. Battery No. 1 utilizes BFG as 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 redistributed throughout the plant.

Clean Coke Oven Gas Export Line and Flare

The clean coke oven gas export line is the fuel distribution line that delivers coke oven gas to other departments/processes at Burns Harbor that fire coke oven gas. Before export, the gas is scrubbed of PM. The export line is equipped with a flare in the event Burns Harbor does not have enough demand for the volume of coke oven gas produced in the batteries. NO_x and SO_2 emissions are generated at the flare stack for the portion of coke oven gas that is not redistributed throughout the plant.

Power Station Boiler Nos. 7-12

The Power Station Boiler Nos. 7-12 produce utility steam for use throughout the Burns Harbor facility. The boilers primarily fire coke oven gas, NG, and BFG, 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. BFG is considered a low-NO_x fuel because it has a lower heating value compared to NG which creates a lower flame temperature and generates significantly less thermal NO_x. The boilers utilize low-NO_x fuel and good combustion practices as NO_x emission control measures. SO_2 emissions from the Power Station Boiler Nos. 7-12 are generated from NG and BFG combustion, also. NG and BFG are considered low-sulfur fuels when compared to other solid and liquid fuels and are utilized as an SO_2 emission control measure.

Blast Furnaces C and D (Stoves, Casthouses, and Flares)
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 BFG, coke oven gas, and NG to heat fresh air for injection. BFG 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. 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 BFG, coke oven gas, and NG 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. BFG is considered a low-NO_x fuel because it has a lower heating value compared to NG which creates a lower flame temperature and generates significantly less thermal NO_x. Therefore, the use of BFG 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 (BFG, NG, and coke oven gas). BFG and NG 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. 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.

The Blast Furnaces C and D Flares produce NO_x and SO_2 due to the combustion of blast furnace waste gas and NG pilots. BFG is a low-NO_x fuel and is utilized as an existing NO_x emission control measure. BFG and NG are considered low-sulfur fuels and are SO_2 emission control measures.

3.3.1 Burns Harbor Four-Factor Analysis of Potential NO_x Control Options

Battery Nos. 1 and 2
The RBLC search and search of air permits for iron and steel mills and similar sources 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 iron and steel mills, air permits from other similar sources were reviewed to identify NO_x emission control measures. Battery No. 1 already utilizes low-NO_x fuel

combustion (BFG), and Battery No. 2 has staged combustion as existing NO_x emission control measures.

The RBLC search 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 Burns Harbor 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. And as previously discussed, EPA stated the following in the New Source Review Workshop Manual "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 byproducts 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 and air permits for iron and steel mills. 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.

Clean Coke Oven Gas Export Line and Flare
The NO_x emissions generated from coke oven gas fired in downstream emission units are dependent on the burner-specific characteristics [e.g., flame temperature, oxygen 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.

Coke oven gas is routed to a bleeder flare in the event Burns Harbor does not have enough demand for the volume of coke oven gas produced in the batteries. There are no additional NO_x emission control measures based on the emission control measures described in the RBLC and air permits for iron and steel mills and similar sources. 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.

Power Station Boiler Nos. 7, 8, 9, 10, 11 and 12

The RBLC search and search of air permits for iron and steel mills and similar sources for boilers NO_x emission control measures identified the use of low-NO_x fuel, SCR, LNB, and ULNB at some sources. The Power Station Boiler Nos. 7-12 already utilize low-NO_x fuel combustion (BFG) and good combustion practices as existing NO_x emission control measures.

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

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 BFG as a primary fuel source) as previously stated. Although LNB/ULNB have been installed and operated on NG-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 BFG and coke oven gas with some supplemental NG 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 represent 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. Additionally, EPA stated that "Historically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives according to the New Source Review Workshop Manual.

As such, the installation of LNB/ULNBs on the Power Station Boiler Nos. 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 Boiler Nos. 7-12, there are no additional NO_x emission control measures based on the emission control measures described in the RBLC and air permits for iron and steel mills. As such, 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.

Blast Furnaces C and D Stoves, Casthouses, and Flare

The RBLC search and search of air permits for iron and steel mills and similar sources for blast furnace stove NO_x emission control measures identified the use of low-NO_x fuel or LNB at some sources. Blast Furnaces C and D already utilize low-NO_x fuel combustion (BFG) as an existing NO_x emission control measure.

The AK Steel Dearborn B and C Furnaces have LNB installed as part of a 2014 PSD Permit; however, it is not clear that LNB offer any additional emission reduction potential compared to the existing NO_x emission control measures (BFG - low-NO_x fuel). EPA stated in the Alternative Control Techniques Document that "the primary fuel is BFG, which is largely CO, has a low heating value, and contains inerts, factors that reduce flame temperature. Thus, the NO_x concentration in blast furnace stove flue gas tends to be low and the potential for NO_x reduction is considered to be small."

Additionally, the Nucor 2010 Permit to Construct Briefing Sheet stated that LNB was eliminated as technically infeasible because LNB 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 NG in order to maintain flame stability and prevent flameouts of the burners. The use of LNB would attempt to stage fuel gas at the limits of combustibility and would prevent the operation of the hot blast stoves. Thus, LNB are not a feasible control technology for the hot blast stoves.

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 Nucor 2010 BACT, emission control measures described in the RBLC and air permits for similar sources.

The RBLC search and search of air permits for iron and steel mills and similar sources for blast furnace casthouses did not identify any NO_x emission control measures. The Nucor 2010 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 and air permits for iron and steel mills. 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.

The RBLC search and search of air permits for iron and steel mills and similar sources 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 and air permits for iron and steel mills. 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.

Table 3-10 Burns Harbor Emission Units NO_x Control Technologies Analyzed or Justification for No Analysis

Emission Unit	Control Technologies Analyzed	No Analysis Justification
Battery Nos. 1 and 2	None	There are no reasonable NO_x emission control measures beyond what is currently installed and operated.
Clean Coke Oven Gas Export Line and Flare	None	There are no reasonable NO_x emission control measures beyond what is currently installed and operated.
Power Station Boiler Nos. 7-12	None	There are no reasonable NO_x emission control measures beyond what is currently installed and operated.
Blast Furnaces C and D	None	There are no reasonable NO_x emission control measures beyond what is currently installed and operated.

3.3.2 NO_x Emissions Trends at the Burns Harbor Facility

Burns Harbor facility-wide NO_x emissions show a slight upward trend over the 11-year evaluation period as reflected in Table 3-3 and Graph 3-1 on page 12 inclusive of projects aimed at NO_x emission reductions. including the permanent idling of thirty-six coke oven gas and/or blast furnace gas fired Slab Mill Soaking Pits and 160-inch Plate Mill I & O Furnace No. 8. The line graph in Graph 3-1 also show the NO_x emissions decrease in 2009 due to the economic downturn in the industry that resulted in reduced production rates that year. However, Burns Harbor facility-wide NO_x emissions gradually ratcheted back up to the highest NO_x emissions level over the 11-year period. The line graph in Graph 3-1 illustrates an overall 4% increase in facility-wide NO_x emissions from 2008 to 2018.

3.3.3 Burns Harbor Reasonable Level of Control for NO_x Emissions

The evaluation for NO_x emission control measures determined that there are no reasonable NO_x emission control measures beyond what is currently installed and operated for the emission units identified; therefore, no cost effectiveness analysis was conducted.

3.3.4 Burns Harbor Four-Factor Analysis of Potential SO_2 Control Options

Battery Nos. 1 and 2

The RBLC search and search of air permits for iron and steel mills and similar sources for coke oven battery SO_2 emission control measures identified the use of wet venturi scrubbers, SDAs (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 iron and steel mills, air permits from other similar sources were reviewed to identify SO_2 emission control measures.

Wet scrubbers can offer SO_2 control performance levels that are generally consistent with SDAs. 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.

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.

Burns Harbor 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. Burns Harbor identified installation of SDAs or a desulfurization plant to be part of the reasonable set of SO_2 emission control measures for further evaluation. The SDAs would require the installation of new PM baghouses to collect the spent sorbent. Installation of SDAs or a desulfurization plant for Battery Nos. 1 and 2 is evaluated as an SO_2 emission control measure.

Clean Coke Oven Gas Export Line and Flare

Certain iron and steel mills and similar sources have onsite coke oven gas desulfurization plants as an SO_2 emission control measure. Burns Harbor 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 is evaluated as a SO_2 emission control measure.

Coke oven gas is routed to the Clean Coke Oven Gas Export Line Flare in the event Burns Harbor does not have enough demand for the volume of coke oven gas produced in the batteries. The RBLC search and search of air permits for iron and steel mills and similar sources for coke oven battery flares SO_2 emission control measures identified the use of coke oven gas desulfurization.

Burns Harbor 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, coke oven gas desulfurization for the Clean Coke Oven Gas Export Line Flare is evaluated as an SO_2 emission control.

Power Station Boiler Nos. 7, 8, 9, 10, 11 and 12

The RBLC search and search of air permits for iron and steel mills and similar sources for boilers SO_2 emission control measures identified the use of low-sulfur fuels at some sources. The Power Station Boiler Nos. 7-12 already utilize low-sulfur fuel combustion (NG and BFG) as an existing SO_2 emission control measure.

It is not appropriate to compare SO_2 emission control measures at other iron and steel 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 (e.g., natural gas, blast furnace gas). Wet scrubbers, spray dryer absorbers, and dry sorbent injection 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-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.

Burns Harbor 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. For the reasons stated under the Clean Coke Oven Gas Export Line and Flare on the previous page, installation of a desulfurization plant was determined not to be reasonable.

Burns Harbor 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 for the Clean Coke Oven Gas Export Line and Flare. 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 for the Clean Coke Oven Gas Export Line and Flare and therefore is not necessary to be readdressed for the Power Station Boiler Nos. 7-12.

Blast Furnaces C and D Stoves, Casthouses, and Flare

The RBLC search and search of air permits for iron and steel mills and similar sources for Blast Furnace Stoves SO_2 emission control measures identified the use of low-sulfur fuel at one source. The Blast Furnaces C and D Stoves already routinely fire low-sulfur fuels (BFG and NG) as an existing SO_2 emission control measure.

The AK Steel Dearborn 2014 PSD Permit did not require additional SO_2 emission control measures. The 2010 Nucor BACT determined that other than the low-sulfur fuels (BFG and NG), 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 and air permits for iron and steel mills. 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.

The RBLC search and search of air permits for iron and steel mills and similar sources for Blast Furnace Casthouses did not identify any SO_2 emission control measures. AK Steel Dearborn 2014 PSD Permit 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 and air permits for iron and steel mills. 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.

The RBLC search and search of air permits for iron and steel mills and similar sources 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 and air permits for iron and steel mills. 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.

3.3.4.1 Cost of Compliance for Potential SO_2 Control Options

Burns Harbor completed cost estimates for installation of SDA on Battery Nos. 1 and 2 and Power Station Boiler Nos. 7-12; DSI on Power Station Boiler Nos. 7-12; and 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 A.

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

interest is assumed in annualizing capital costs. The resulting cost-effectiveness calculations are summarized in Appendix A.

3.3.4.2 Time Necessary for Potential SO_2 Control Options 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 Burns Harbor's Title V operating permit to allow construction to commence, then time 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. If a rulemaking for the site-specific SIP limit is necessary, then this process could take even longer.

3.3.4.3 Energy and Non-Air Impacts of Potential SO_2 Control Options

The SDA on Battery Nos. 1 and 2 and SDA or DSI on the Power Station Boiler Nos. 7-12 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 SDA and DSI have been included in the cost analyses found in Appendix A. The SDA and DSI 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, 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.

3.3.4.4 Remaining Useful Life for SO_2 Control Options

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

Table 3-11 Burns Harbor Units SO_2 Control Technologies Analyzed or Justification for No Analysis

Emission Unit	Control Technologies Analyzed	No Analysis Justification
Battery Nos. 1 and 2	Spray Dryer Absorber	
Clean Coke Oven Gas Export Line and Flare	Coke Oven Gas Desulfurization	
Power Station Boiler Nos. 7-12	Spray Dryer Absorber Dry Sorbent Injection	
Blast Furnaces C and D	None	There are no reasonable SO_2 emission control measures beyond what is currently installed and operated.

3.3.5 SO_2 Emissions Trends at the Burns Harbor Facility

Burns Harbor facility-wide SO_2 emissions show a downward trend over the 11-year evaluation period as reflected in Table 3-5 and Graph 3-2 on pages 17 and 18, respectively, as a result of extensive projects aimed at emission reductions. This includes the permanent idling of thirty-six coke oven gas and/or blast furnace gas fired Slab Mill Soaking Pits and 160-inch Plate Mill I & O Furnace No. 8. The line graph in Graph 3-2 illustrates that Burns Harbor facility-wide SO_2 emissions in 2009 also show the economic downturn that resulted in reduced production rates in the industry during that year. The overall facility-wide SO_2 emissions decreased 16% from 2008 to 2018.

3.3.6 Burns Harbor Reasonable Level of Control for SO_2 Emissions

The reasonable set of SO_2 emission control measures beyond what is currently installed and operated various operations at Burns Harbor are as follows: SDA for Battery No. 1 and Battery No. 2, Coke Oven Gas Desulfurization for the Clean Coke Oven Gas Export Line and Flare and SDA and DSI for Power Station Boilers 7-12. The associated SO_2 cost-effectiveness values ($ per ton of emissions reduction) for these emission units are listed below (See Cost Effectiveness and Cost Estimate Spreadsheets in Appendix A):

Emission Unit	Control Measure	Cost Effectiveness
Battery #1	Spray Dryer Absorber	$6,300
Battery #2	Spray Dryer Absorber	$5,300
Clean Coke Oven Gas Export Line and Flare	Coke Oven Gas Desulfurization	$4,000
Power Station Boiler 7	Spray Dryer Absorber	$16,066
Power Station Boiler 7	Dry Sorbent Injection	$8,800
Power Station Boiler 8	Spray Dryer Absorber	$21,700
Power Station Boiler 8	Dry Sorbent Injection	$9,900
Power Station Boiler 9	Spray Dryer Absorber	$26,800
Power Station Boiler 9	Dry Sorbent Injection	$11,500
Power Station Boiler 10	Spray Dryer Absorber	$42,000
Power Station Boiler 10	Dry Sorbent Injection	$16,700
Power Station Boiler 11	Spray Dryer Absorber	$25,300

Power Station Boiler 11	Dry Sorbent Injection	\$10,900
Power Station Boiler 12	Spray Dryer Absorber	\$20,300
Power Station Boiler 12	Dry Sorbent Injection	\$10,000

3.4 United States Steel Corporation - Gary Works (U.S. Steel) NO_x and SO_2 Emissions and Controls

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 four emission unit groups identified in IDEM's RFI are listed in the table below; and the sources of NO_x and/or SO_2 emissions and existing control measures are described in this section for each emission unit chosen for four-factor analysis evaluations.

Table 3-12 Gary Works Emission Units and Pollutants Identified for Four-Factor Analysis

Emission Unit	Applicable Pollutant(s)
No. 3 Sinter Plant Sinter Strands (2)	NO_x, SO_2
No. 14 Blast Furnace Stoves and Casthouse	NO_x, SO_2
Waste Heat Boiler 1 and 2	NO_x
84" Hot Strip Mill Furnace-Reheat Furnace Nos. 1, 2 and 3	NO_x

<u>No. 3 Sinter Plant Strands</u>

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 PM and SO_2 emissions. Each train consists of reheat burners, cyclones, and is 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 NG burners. NO_x emissions are generated from the associated combustion of the coke and NG and the combustion of NG 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 NG fuel. A simplified version of the existing emission control measures for the No. 3 Sinter Plant windbox exhaust is presented in Graph 2-1 of the Gary Works four-factor analysis submittal. The exhaust treatment reduces PM and SO_2 emissions.

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 to 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.

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 BFG and supplemental NG to heat fresh air for injection. The blast furnace is also able to inject pulverized coal and NG. BFG 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 NG (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 NG. BFG burns at a cooler temperature, which prevents the majority of thermal NO_x formation when compared to NG combustion. Therefore, the use of BFG in the No. 14 Blast Furnace Stoves is an existing NO_x emission control measure.

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 NG 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 NG-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 NG combustion. These 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 minimizes excess air.

3.4.1 Gary Works Four-Factor Analysis of Potential NO_x Control Options

No. 3 Sinter Plant Sinter Strands

The RBLC search and search of air permits for iron and steel mills and similar sources for sinter strand NO_x emission control measures identified no applicable control measures beyond what is currently installed and operated for these emission units. In addition, there are no additional NO_x emission control measures based on the Nucor 2010 BACT. 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 Nucor 2010 BACT and, therefore, are considered effective emission controls.

No. 14 Blast Furnace Stoves and Casthouse

The RBLC search and search of air permits for iron and steel mills and similar sources for blast furnace stove NO_x emission control measures identified the use of low-NO_x fuel or LNB at some sources. The No. 14 Blast Furnace Stoves already utilize low-NO_x fuel combustion (BFG) as a NO_x emission control measure. The AK Steel Dearborn B and C Furnaces have LNB installed as part of a 2014 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.

As previously cited, the EPA stated the following in the Alternative Control Techniques Document, "(…) the primary fuel is BFG, which is largely CO, has a low heating value, and contains inerts, factors that reduce flame temperature. Thus, the NO_x concentration in blast furnace stove flue gas tends to be low and the potential for NO_x reduction is considered to be small."

It is important to note that Gary Works historically represented the actual NO_x emissions generated from the supplement NG combustion at the No. 14 Blast Furnace Stoves based on a conservatively high AP-42 uncontrolled pre-New Sources Performance Standards NG boiler emission factor [280 pound per million standard cubic foot (lb/MMscf) or 0.275 pound per million British thermal units (lb/MMBtu)]. Since the NG is fired as a supplement to the BFG to meet operating temperatures, the associated AP-42 NG emission factor value overrepresents thermal NO_x formation because the flame temperatures are less than what would be achieved when firing NG exclusively (i.e., the 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 Nucor 2010 Permit to Construct Briefing Sheet stated that LNB was eliminated as technically infeasible for the following rationale: "LNB 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 NG in order to maintain flame stability and prevent flameouts 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."

Since LNB represent a negligible or potentially small emission reduction potential, 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 the No. 14 Blast Furnace Stoves and are not evaluated further in this analysis.

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 Nucor 2010 BACT, emission control measures described in the RBLC, and air permits for similar sources. Furthermore, the existing NO_x emission control measures are equivalent to those determined to be BACT in the Nucor 2010 BACT evaluation and determination; and, therefore, are considered effective emission controls.

84" Hot Strip Mill Reheat Furnaces and Waste Heat Boilers

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.

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 and the air permits for similar sources.

The RBLC search identified two instances of SCR for NO_x emission control; a reheat furnace at Thyssenkrupp 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 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 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. Thus, 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.

3.4.1.1 Cost of Compliance for Potential NO_x Control Options

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 A.

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

3.4.1.2 Time Necessary for Potential NO_x Control Options Compliance

The amount of time needed for full implementation of the installation of LNB 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. If a rulemaking for the site-specific SIP limit is necessary, then this process could take even longer.

3.4.1.3 Energy and Non-Air Impacts of Potential NO_x Control Options

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.

3.4.1.4 Remaining Useful Life for NO_x Control Options

Because Gary Works is assumed to continue operations for the foreseeable future, the useful life of 20 years for the individual emission control measures is used to calculate emission reductions, amortized costs, and cost-effectiveness on a dollar per ton basis.

Table 3-13 Gary Works Emission Units NO_x Control Technologies Analyzed or Justification for No Analysis

Emission Unit	Control Technologies Analyzed	No Analysis Justification
No. 3 Sinter Plant Sinter Strands (2)	None	There are no reasonable NO_x emission control measures beyond what is currently installed and operated.
No. 14 Blast Furnace Stoves and Casthouse	None	There are no reasonable NO_x emission control measures beyond what is currently installed and operated.
84" Hot Strip Mill Reheat Furnaces Nos. 1-4 and Waste Heat Boilers Nos. 1 and 2	LNB	

3.4.2 NO_x Emissions Trends at the Gary Works Facility

Gary Works facility-wide NO_x emissions show a downward trend over the 11-year evaluation period as reflected in Table 3-3 and Graph 3-1 on page 12 as a result of extensive projects, including shutting down three coke battery units. The line graph in Graph 3-1 also show the NO_x emissions decrease in 2009 due to the economic downturn in the industry that resulted in reduced production rates that year. Gary Works facility-wide NO_x emissions decreased 25% from 2008 to 2018.

3.4.3 Gary Works Reasonable Level of Control for NO_x Emissions

LNB technology was determined to be the reasonable NO_x emission control measure to reduce NO_x emissions, beyond what is currently installed and operated, from the 84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4, Waste Heat Boiler No. 1, and Waste Heat Boiler No. 2. The associated NO_x cost-effectiveness values ($ per ton of emissions reduction) for the addition of LNB technology to control NO_x emissions are $14,142 per ton of NO_x removed for Reheat Furnaces No. 1 through No. 4, $6,130 per ton of NO_x removed for Waste Heat Boiler No. 1 and $7,000 per ton of NO_x removed for Waste Heat Boiler No. 2 as shown in the Cost Effectiveness and Cost Estimate spreadsheets in Appendix A.

3.4.4 Gary Works Four-Factor Analysis of Potential SO_2 Control Options

<u>No. 3 Sinter Plant Sinter Strands</u>

The RBLC search and search of air permits for iron and steel mills and similar sources for sinter plant sinter strand SO_2 emission control measures identified the use of a wet scrubber at a similar source. 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. A wet scrubber has functionally equivalent SO_2 control performance compared to the existing quench reactor with the dry-lime scrubber at Gary Works' sinter plant; therefore, a wet scrubber does not represent additional SO_2 emission reduction potential compared to the existing control measures and is not evaluated further.

The Nucor 2010 BACT identified DSI as technically feasible but it was listed at a lower control efficiency than the lime spray dry scrubber. Therefore, the existing SO_2 emission control measures represent the best SO_2 emission reduction potential based on the Nucor 2010 BACT and emission control measures described in the RBLC and air permits for similar sources. There are no additional SO_2 emission control measures. As such, the No. 3 Sinter Plant Sinter Strands have no reasonable set of SO_2 emission control measures.

No. 14 Blast Furnace Stoves and Casthouse

The No. 14 Blast Furnace Stoves routinely fire low-sulfur fuels (BFG and pipeline-grade NG) as an existing SO_2 emission control measure. The Nucor 2010 BACT determined that other than the low-sulfur fuels (BFG and NG), no additional add-on SO_2 emission control measures are technically feasible. There are also no additional SO_2 emission control measures based on the emission control measures described in the RBLC and air permits for similar sources. As such, the No. 14 Blast Furnace Stoves have no reasonable set of SO_2 emission control measures and the existing SO_2 emission control measures are equivalent to those determined to be BACT in the Nucor 2010 BACT and, therefore, are considered effective emission controls.

There are no existing SO_2 emission control measures associated with the No. 14 Blast Furnace Casthouse at similar sources, as represented in the RBLC and their respective air permits. There are also no additional SO_2 emission control measures based on the 2010 Nucor BACT, emission control measures described in the RBLC and air permits for similar sources. Therefore, 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 and 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.

Table 3-14 Gary Works Emission Units SO_2 Control Technologies Analyzed or Justification for No Analysis

Emission Unit	Control Technologies Analyzed	No Analysis Justification
No. 3 Sinter Plant Sinter Strands (2)	None	There are no reasonable SO_2 emission control measures beyond what is currently installed and operated.
No. 14 Blast Furnace Stoves and Casthouse	None	There are no reasonable SO_2 emission control measures beyond what is currently installed and operated.
Waste Heat Boiler 1 and 2	None	There are no reasonable SO_2 emission control measures beyond what is currently installed and operated.
84" Hot Strip Mill Furnace-Reheat Furnace Nos. 1, 2, 3, and 4	None	There are no reasonable SO_2 emission control measures beyond what is currently installed and operated.

3.4.5 SO_2 Emissions Trends at the Gary Works Facility

Gary Works facility-wide SO_2 emissions show a downward trend over the 11-year evaluation period as reflected in Table 3-5 and Graph 3-2 on pages 17 and 18, respectively, as a result of extensive projects, including the installation of SO_2 emission control measures on the No. 3 Sinter Plant Sinter Strand. The line graph in Graph 3-2 illustrates Gary Works facility wide SO_2 emissions in 2009 also show the economic downturn that resulted in reduced production rates in the industry during that year. The overall facility-wide SO_2 emissions decreased 34% from 2008 to 2018.

3.4.6 Gary Works Reasonable Level of Control for SO_2 Emissions

The evaluation for SO_2 emission control measures determined that there are no reasonable SO_2 emission control measures beyond what is currently installed and operated for the emission units identified; therefore, no cost effectiveness analysis was conducted.

3.5 Clean Air Act Regulations Controlling Iron and Steel Mill Plants

NO_x and SO_2 emissions from Indiana's integrated iron and steel mill operations are generated from blast furnace gas and natural gas combustion. BFG is the primary fuel utilized for the largest NO_x and SO_2 emitting emission units at the iron and steel mill facility operations used to produce steel from iron ore pellets, coke, metal scrap, and other raw materials using furnaces and other processes. This source category includes sinter production, iron preparation, iron production, and steel production. BFG-fired boilers, furnaces, and other processes at iron and still mill operations use the blast furnace gas by-product from blast furnaces as a fuel, reducing the need for flaring, which reduces the overall emissions from various operations at these facilities.

The EPA published the Cross State Air Pollution Rule (CSAPR) in the Federal Register (FR) on August 8, 2011 (76 FR 48208)[1] in order to reduce the interstate transport of fine particulate matter and ozone. The rule replaces EPA's Clean Air Interstate Rule (CAIR), which was remanded by a December 2008 court decision that kept CAIR in place temporarily while directing EPA to issue a replacement rule. CSAPR requires twenty-eight states in the eastern half of the United States, including Indiana, to significantly improve air quality by reducing NO_x and SO_2 power plant emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in other states. To speed implementation, U.S. EPA adopted Federal Implementation Plans (FIPs) for each of the states covered by CSAPR in 2015 and encouraged States to submit SIPs. CAIR had included large non-electric generating unit (non-EGU) boilers and combustion turbines in the CAIR NO_x Ozone Season Trading Program; however, large non-EGU units were not carried over into the CSAPR Trading Program FIP. Since the CSAPR FIP applies only to EGUs, large non-EGUs remain subject to the NO_x SIP Call rule requirements at 40 CFR 51.121.

The NO_x SIP Call generally requires that states choosing to rely on non-EGUs for meeting NO_x SIP Call emission reduction requirements must establish a NO_x mass emissions cap on each source and require monitoring in accordance with 40 CFR 75, Subpart H. EPA did not require enforceable caps on either individual non-EGUs or all of the non-EGUs as a group. States that relied on large non-EGUs for emission reductions required by the NO_x SIP Call had to identify another way to ensure continued compliance with the NO_x SIP Call. IDEM submitted a revision to Indiana's SIP to amend state rules to move monitoring requirements for non-EGUs at 326 IAC 24-3-11 to the NO_x rules at 326 IAC 10 and amend requirements for BFG units as described below. Indiana received EPA approval on July 24, 2020. The only remaining requirements for the trading program non-EGUs is to monitor for NO_x in accordance with 40 CFR 75, Subpart H.

As part of the amendments removing non-EGUs from the CAIR trading program Indiana also moved the BFG units that were part of the trading program to existing requirements at 326 IAC 10-3 to consistently apply a NO_x emission limit to all BFG units under the NO_x SIP Call.

Indiana's SIP submittal included a streamlined demonstration to demonstrate that the total ozone-season NO_x emissions from large non-EGUs could not exceed the large non-EGU budget imposed by the NO_x SIP Call, even if these units were to operate every hour of the ozone season. The demonstration included the total ozone season NO_x emissions without the steel mills' BFG units because these units were not included in the final budget analysis. The rationale was reductions from these units were not needed to meet Indiana's NO_x SIP Call obligations, even though some of these units were included in Indiana's NO_x Budget Trading Program. Table 4 in the November 8, 2001 FR[2] for final NO_x Budget Trading Program SIP approval shows zero reductions to be achieved by the blast furnace gas units.

[1] Federal Register, Volume 76, Issue 152 (August 8, 2011), Page 48208
[2] Federal Register, Volume 66, Issue 217 (November 8, 2001), Page 56469

During the development stages of the Indiana NO_x SIP Call rules, all BFG units were included in the trading program. However, after CAIR was remanded, IDEM in coordination with EPA determined that removing these units from the trading program would have no net effect on the amount of total reductions needed to be achieved by the State (since IDEM was not projecting emission reductions from these units to meet the trading program budget). These units are considered low-NO_x emitters on a lb/MMBtu basis with no viable control options available. BFG boilers use the blast furnace gas by-product from blast furnaces as a fuel, reducing the need for flaring, which reduces the overall emissions from the process.

4.0 PLASTICS MANUFACTURING PLANT

4.1 SABIC Innovative Plastics, Mt. Vernon LLC (SABIC) NO_x and SO_2 Emissions and Controls

SABIC is a stationary plastics manufacturing plant. The plant's chemical and plastics manufacturing operations include numerous products that are sold to end-use customers and many intermediate products necessary for end-use plastics products. These intermediates are used at Mt. Vernon 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. The two emission unit groups addressed in IDEM's RFI are described below and the source of each units' NO_x and SO_2 emissions and existing control measures are described in this section.

Table 4-1 SABIC Emission Units and Pollutants Identified for Four-Factor Analysis

Emission Unit	Applicable Pollutant(s)
Co-generation Unit	NO_x, SO_2
Phosgene COS Vent Oxidizer and Flare Associated with Building 6 Carbon Monoxide Generators	SO_2

Co-generation Unit (COGEN)

SABIC began construction of the COGEN unit in 2015. The unit was fully operational in the fourth quarter of 2016. The installation of the 1,812 MMBTU/hr stationary NG-fired combustion turbine and nominal 486 MMBTU/hr NG-fired duct burner with a HRSG allowed SABIC to cease using coal as fuel to generate steam for process operations.

NO_x formation occurs by three fundamentally different mechanisms. The principal mechanism with turbines firing NG is thermal NO_x, which arises from the thermal dissociation and subsequent reaction of nitrogen and oxygen 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. NG has negligible chemically bound fuel nitrogen, although some molecular nitrogen maybe present. It can be assumed that all NO_x formed from NG 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 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 NG is typically premixed with more than 50 percent theoretical air, which results in lower flame temperatures and 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., NG-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. SABIC's current Title V permit contains conditions that limit the 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 CEMS as required by its Title V permit.

COGEN is a NG-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 NG which pursuant to 40 CFR 72.2 must contain 0.5 grains/100 scf or less of sulfur. Pipeline NG 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 according to 40 CFR 72.2. NG contains 0.5 grains or less of total sulfur per 100 scf. The low sulfur input into the COGEN results in low SO_2 emissions at the COGEN stack (i.e., post combustion).

Phosgene COS Vent Oxidizer and Flare (Associated with Building 6 Carbon Monoxide Generators)

The SO_2 emissions from the CO generation process are created during the incineration of the COS vent stream in the Phosgene COS Vent Oxidizer (COS Vent Oxidizer). The COS vent stream, containing reduced sulfur compounds, predominately originates from the reduction of CO_2 over petcoke to generate purified CO.

SABIC operates sixteen CO generators to produce a high-purity CO as an intermediate to be used for phosgene generation in the Phosgene process area at the Mt Vernon facility. The sulfur content of the petcoke is analyzed frequently by SABIC or the petcoke supplier. A mass balance of the total sulfur input to the CO generators is required in SABIC's current Title V permit to comply with the PSD avoidance limit. The SO_2 that exits the COS Vent Oxidizer originates as sulfur in the petcoke.

The Phosgene process area 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 COS Vent Oxidizer controls the production of CO. The chlorine gas is generated in another process area within the Mt. Vernon facility. Chlorine 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).
- 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. 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 NG-fired combustion turbine with a NG-fired duct burner and HRSG.
- 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 is routed to the COS Vent Oxidizer.

- The SO_2 emissions addressed in this four-factor analysis, is a byproduct created during the incineration of the Phosgene COS vent stream in the COS Vent Oxidizer.
- 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.

4.1.1 SABIC Four-Factor Analysis of Potential NO_x Control Options

SABIC has evaluated the following additional emission control measures for NO_x reduction for the COGEN and the technical feasibility of these options is discussed in this section:

- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)
- Selective Catalytic Oxidizer with additional capability of reducing NO_x emissions (SCONOx™)

SCR is an exhaust gas treatment process in which ammonia (NH_3) is injected into the exhaust gas upstream of a catalyst bed. 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. Therefore, SCR is a technically feasible NO_x control technology for SABIC's COGEN.

The SNCR process reduces NO_x emissions using NH_3 or urea injection similar to SCR but operates only at higher temperatures. 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 nitrogen 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.

A relatively new post-combustion technology from EmeraChem is SCONOx™, which utilizes a coated oxidation catalyst to remove both NO_x and CO without a reagent such as ammonia. SCONOx™ has been primarily installed on co-generation or combined cycle systems where the exhaust gas temperature is reduced by recovering energy to produce steam. The SCONOx™ 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 SCONOx™, and it is eliminated from further evaluation in SABIC's four-factor analysis.

4.1.1.1 Cost of Compliance for Potential NO_x Control Options

The EPA Cost Control Manual was used for SCR along with site-specific data inputs to estimate the cost of installing a SCR to control NO_x emissions from the COGEN. An overall summary of estimated cost is presented in Appendix A with a detailed breakdown.

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.

4.1.1.2 Time Necessary for Potential NO_x Control Options Compliance

Installation of a SCR to reduce NO_x emissions from the COGEN would require substantial capital and operating cost investments. A detailed design engineering project would need to be conducted, which is not included in the estimated costs (2019 dollars) of NO_x emissions reduction summarized in Appendix A.

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. If a rulemaking for the site-specific SIP limit is necessary, then this process could take even longer.

4.1.1.3 Energy and Non-Air Impacts of Potential NO_x Control Options

Potential energy and non-air environmental impacts of SCR include:

- Creation of electric demand that did not exist prior to installation.
- Creation of a new solid waste stream (spent catalyst).
- Necessity for storage of large amounts of liquid ammonia that may be regulated by EPA's risk management program 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 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.

4.1.1.4 Remaining Useful Life of Potential NO_x Control Options

There are no enforceable limitations on the remaining useful life for the COGEN or any other units at Mt Vernon. However, the entire COGEN facility was constructed in 2015 to 2016 and began full operation in fourth quarter 2016. For the purposes of this analysis, a 20-year remaining useful life was used in the cost calculations detailed in Appendix A.

Table 4-2 SABIC Emission Units NO_x Control Technologies Analyzed or Justification for No Analysis

Emission Unit	Control Technologies Analyzed	No Analysis Justification
Co-generation Unit	SCR	

4.1.2 NO_x Emissions Trends at the SABIC Facility

SABIC facility-wide NO_x emissions show a significant downward trend over the 11-year evaluation period as reflected in Table 3-3 and Graph 3-1 on page 12 as a result of the COGEN facility commencement of operations in 2016. The line graph in Graph 3-1 shows the substantial decrease in NO_x emissions after ending the use of coal as fuel to generate steam for process operations. SABIC facility-wide NO_x emissions decreased 84% from 2008 to 2018.

4.1.3 SABIC Reasonable Level of Control for NO_x Emissions

The reasonable NO_x emission control measure beyond what is currently installed and operated for the COGEN at SABIC is a SCR. The associated NO_x cost-effectiveness value ($ per ton of emissions reduction) for the addition of SCR to reduce NO_x emissions from the COGEN is $25,691 per ton of NO_x removed (See Cost Effectiveness and Cost Estimate Spreadsheets in Appendix A).

4.1.4 SABIC Four-Factor Analysis of Potential SO_2 Control Options

The four-factor analyses for the COGEN and COS Vent Oxidizer 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:

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 Mt. Vernon facility.

<u>COGEN</u>

The COGEN is a NG-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 NG which pursuant to 40 CFR 72.2 must contain 0.5 grains/100 scf or less of sulfur. As defined in 40 CFR 72.2, NG 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 NG contains 0.5 grains or less of total sulfur per 100 scf. Additionally, pipeline NG must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 Btu/scf. The low sulfur input into the COGEN results in low SO_2 emissions at the COGEN stack (i.e., post combustion).

The COGEN is fueled by low sulfur, pipeline quality, NG. While it may be theoretically feasible to install a wet or dry scrubber system on a NG-fired turbine such as the COGEN, due to the inherently low SO_2 emission concentration associated with the combustion of NG, these systems are not cost effective and regulatory agencies do not require such controls or even the evaluation of such controls. Therefore, no further analysis of additional SO_2 controls for COGEN is conducted.

<u>COS Vent Oxidizer</u>

SABIC 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.

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 SABIC. 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 SABIC. With proper scrubber pH and temperature control, the potential plugging of the media from precipitation of salts can be avoided. Therefore, 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.

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 FGD and dry FGD. To further qualify the need for a high gas exhaust flow and concentration, the EPA Cost Control Manual for SO_2 and Acid Gas Controls requires data inputs such as fuel - higher heating value and boiler - output megawatt rating. Neither of these data inputs are applicable to SABIC'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. 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.

4.1.4.1 Cost of Compliance for Potential SO_2 Control Options

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 Appendix A with a detailed breakdown.

- As appropriate, SABIC used site-specific data and engineering judgement to refine the estimated costs summarized in Appendix A, which contains additional details, references, and data sources for this SO_2 cost analysis.
- The total capital investment which includes a retrofit factor, uses cost data from a similar wet packed tower scrubber installation at SABIC in 2010.
    - SABIC'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.).
    - 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 CEPCI was used to ratio the 2010 project cost to 2019 dollars.
- The factors provided in the EPA 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.

4.1.4.2 Time Necessary for Potential SO_2 Control Options Compliance

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 system, would take 2 to 3 years if additional SO_2 control is required for regional haze visibility reasonable progress. This could take even longer if a rulemaking for the site-specific SIP limit is necessary. 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 Appendix A 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.

4.1.4.3 Energy and Non-Air Impacts of Potential SO_2 Control Options

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 SABIC 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 SABIC's wastewater facilities. The cost of wastewater treatment modifications is not analyzed in this report.

4.1.4.4 Remaining Useful Life for SO_2 Control Options

The remaining useful life 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.

Table 4-3 SABIC Emission Units SO_2 Control Technologies Analyzed or Justification for No Analysis

Emission Unit	Control Technologies Analyzed	No Analysis Justification
Co-generation Unit	None	There are no reasonable SO_2 emission control measures beyond what is currently installed and operated.
Phosgene COS Vent Oxidizer and Flare Associated with Building 6 Carbon Monoxide Generators	Packed-Bed Wet Scrubber	

4.1.5 SO_2 Emissions Trends at the SABIC Facility

SABIC facility-wide SO_2 emissions show a significant downward trend over the 11-year evaluation period, as reflected in Table 3-5 (on page 17) and Graph 3-2 (on page 18), as a result of the COGEN facility's commencement of operations in 2016. The line graph in Graph 3-2 show the SO_2 emissions decreased substantially 2017 emissions after ceasing the use of coal as fuel to generate steam for process operations. SABIC facility-wide SO_2 emissions decreased 89% from 2008 to 2018.

4.1.6 SABIC Reasonable Level of Control for SO_2 Emissions

The reasonable SO_2 emission control measure beyond what is currently installed and operated for the COS Vent Oxidizer at SABIC is a Packed-Bed Wet Scrubber. The associated SO_2 cost-effectiveness value ($ per ton of emissions reduction) for the addition of a Packed-Bed Wet Scrubber for the COS Vent Oxidizer is $12,449 per ton of SO_2 emissions reduction (See Cost Effectiveness and Cost Estimate Spreadsheets in Appendix A).

4.2 Clean Air Act Regulations Controlling Plastics Manufacturing Plants

The COGEN project includes new equipment subject to New Source Performance Standards (NSPS) that apply to the affected units. The COGEN facility is an affected EGU pursuant to 40 CFR 60, Subpart TTTT - Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units; however, The GHG standards in 40 CFR 60, Subpart TTTT, are not applicable to the COGEN emission unit because it is a combined heat and power unit that is subject to a federally enforceable permit condition limiting annual net-electric sales per 40 CFR 60.5509(b)(3).

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. SABIC's current Title V permit contains conditions that limit the COGEN's NO_x emissions to 40 CFR 60 Subpart KKKK-Standards of Performance for Stationary Combustion Turbines.

5.0 ALUMINUM PRODUCTION FACILITY

5.1 Warrick Newco LLC, formerly Alcoa Warrick Operations LLC (Alcoa) NO_x and SO_2 Emissions and Controls

Alcoa is a stationary aluminum production plant. Its primary aluminum reduction operations consist of the Alcoa potlines and potlines support plant, paste production plant, and anode baking plant. The two emission unit groups selected for SO_2 four-factor analysis in IDEM's RFI are listed below and the source of each unit's SO_2 emissions and existing control measures are described in this section. NO_x four-factor analyses were not requested by IDEM for the two emission unit groups selected.

Table 5-1 Alcoa Warrick Emission Units and Pollutants Identified for Four-Factor Analysis

Emission Unit	Applicable Pollutant(s)
Potlines 2 through 6	SO_2
Anode Baking Ring Furnace & A-446 Dry Alumina Scrubbers	SO_2

<u>Potline Nos. 2, 3, 4, 5, and 6</u>
The Alcoa Potlines consists of the five center-worked prebake one (CWPB1) potlines controlled by fluidized bed scrubbers (for potlines 2, 5, and 6), alumina injection and fabric filtration systems (for potlines 3 and 4). The SO_2 emissions are generated by the consumption of the carbon anode during the aluminum smelting process. The facility's hourly SO_2 emissions limitations translate into a limit on the incoming sulfur content of the petroleum coke used to form the anode of ~2% sulfur, the lowest sulfur content of all aluminum smelters in the United States. Alcoa's coke supplier must import low sulfur calcined petroleum coke from South America in order to meet the ~2% limit, at a considerable cost to the facility. NO_x emissions have not been directly measured from this process.

<u>Potline No. 2</u>
Potline No. 2 is a CWPB1 Potline, consisting of 150 pots. It was constructed in 1962 with a maximum aluminum production rate of 7.99 tons per hour. Primary emissions are controlled by the Potline No.2 A-398 pollution control system and exhaust at Stacks 160C1.1-160C1.36. The Potline No. 2 A-398 pollution control system is a fluidized bed scrubber and baghouse system, consisting of twelve fluidized bed scrubbers and baghouses, with a total gas flow rate of 480,000 acfm at 2000°F. Secondary emissions are uncontrolled and exhaust at roof monitors 103M.1 and 104M.1.

Potline No. 3

Potline No. 3 is a CWPB1 Potline, consisting of 150 pots. It was constructed in 1965 with a maximum aluminum production rate of 7.99 tons per hour. Primary emissions are controlled by the gas treatment center (GTC) system and exhausts at Stack GTC. Potline No. 3 GTC is an alumina injection and fabric filtration system, with a total gas flow rate of 1,000,000 acfm at 1700°F and exhausting at Stack GTC. Secondary emissions are uncontrolled and exhaust at roof monitors 105M.1 and 106M.1.

Potline No. 4

Potline No. 4 is a CWPB1 Potline, consisting of 150 pots. It was constructed in 1965 with a maximum aluminum production rate of 7.99 tons per hour. Primary emissions are controlled by the GTC system and exhaust at Stack GTC. Secondary emissions are uncontrolled and exhaust at roof monitors 107M.1 and 108M.1.

Potline No. 5

Potline No. 5 is a CWPB1 Potline, consisting of 150 pots. It was constructed in 1968 with a maximum aluminum production rate of 7.99 tons per hour. Primary emissions are controlled by the Potline No. 5 A-398 pollution control system and exhausts at Stacks 161B5.1-161B5.36. The Potline No. 5 A-398 pollution control system in a fluidized bed scrubber and baghouse system, consisting of twelve fluidized bed scrubbers and baghouses with a total gas flow rate of 480,000 acfm at 2000°F. Secondary emissions are uncontrolled and exhaust at roof monitors 109M.1 and 110M.1.

Potline No. 6

Potline No. 6 is a CWPB1 Potline, consisting of 150 pots. It was constructed in 1968 with a maximum aluminum production rate of 7.99 tons per hour. Primary emissions are controlled by the Potline No. 6 A-398 pollution control system and exhausts at Stacks 161B6.1-161B6.36. The Potline No. 6 A-398 pollution control system is a fluidized bed scrubber and baghouse system, consisting of twelve fluidized bed scrubbers and baghouses, with a total gas flow rate of 480,000 acfm at 2000°F. Secondary emissions are uncontrolled and exhaust at roof monitors 111M.1 and 112M.1.

Anode Baking Ring Furnace Description

The Anode Baking Ring Furnace is an above-ground NG furnace that was constructed in 1981 and rebuilt in 2003. It has a capacity of 21.42 tons of green anodes per hour and it is equipped with an A-446 pollution control system. The A-446 pollution control system consists of three reactor sections with baghouses for PM and PM_{10} control and dry alumina scrubbers for total fluoride and SO_2 control. The system operates with a minimum of two reactor sections at any one time. SO_2 emissions from the anode baking ring furnace are primarily from the sulfur in the coal tar pitch, which is used to bind the petroleum coke together during the anode forming process. Pursuant to the facility's Title V air permit, the pitch sulfur content may not exceed 0.8%. NO_x emissions, although not directly measured, are expected to be primarily from the combustion of NG.

5.1.1 Alcoa Potential Four-Factor Analysis of Potential SO_2 Control Options

Alcoa chose a FGD system for Potlines 2-6 and the Anode Baking Ring Furnace and associated A-446 Dry Alumina Scrubbers. SO_2 emissions from these emission units are primarily due to the sulfur content in the materials used in the Potlines and Potlines Support and Anode Baking Ring Furnace and associated A-446 Dry Alumina Scrubbers operations. Since there are no pollution control devices associated with the potlines or anode baking ring furnace and Alcoa received a budgetary proposal for a FGD to control SO_2 emissions from the potlines, the FGD is evaluated for the potlines and the anode baking ring furnace.

5.1.1.1 Cost of Compliance for Potential SO_2 Control Options

In July 2007, Babcock Power Environmental (Babcock Power) provided Alcoa a budgetary proposal for a FGD system for the control of SO_2 emissions from Potlines 2 through 6. To estimate the capital cost of installing a 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 a FGD system for the Anode Baking Ring Furnace based on the flue gas parameters provided by Alcoa.

5.1.1.2 Time Necessary for Potential SO_2 Control Options 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. This could take even longer if a rulemaking for the site-specific SIP limit is necessary.

5.1.1.3 Energy and Non-Air Impacts of Potential SO_2 Control Options

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 a 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 PM emissions on site. The storage and handling of the reagent and byproduct will also increase PM emissions from the facility. In addition, some FGD technologies are based on chemical reactions that create carbon dioxide, a greenhouse gas and regulated pollutant.

5.1.1.4 Remaining Useful Life for SO_2 Control Options

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.

Table 5-2 Alcoa Emission Units SO_2 Control Technologies Analyzed or Justification for No Analysis

Emission Unit	Control Technologies Analyzed	No Analysis Justification
Potlines 2-6	Flue-Gas Desulfurization	
Anode Baking Ring Furnace & A-446 Dry Alumina Scrubbers	Flue-Gas Desulfurization	

5.1.2 SO_2 Emissions Trends at the Alcoa Facility

Alcoa facility-wide SO_2 emissions show a significant downward trend over the 11-year evaluation period as reflected in Table 3-5 and Graph 3-2 on pages 17 and 18, respectively. The line graph in Graph 3-2 shows SO_2 emissions decreased substantially in 2016 (from 4,147 tons in 2015 which is the highest reported SO_2 emissions over the 11-year evaluation period to 24 tons in 2017) due to reduced production rates. Alcoa suspended the potline operations in 2016 and 2017 to consider the extent of future operations. Potline operations were brought back on-line in 2018. Alcoa facility-wide SO_2 emissions decreased 58% from 2008 to 2018.

5.1.3 Alcoa Reasonable Level of Control for SO_2 Emissions

The reasonable SO_2 emission control measure beyond what is currently installed and operated for Potlines 2-6 and Anode Baking Ring Furnace & A-446 Dry Alumina Scrubbers unit at Alcoa is FGD. The associated SO_2 cost-effectiveness values ($ per ton of emissions reduction) for the addition of FGD for Potlines 2-6 is $5,889 per ton of SO_2 emissions reduction and $16,787 per ton of SO_2 emissions reduction for the Anode

Baking Ring Furnace & A-446 Dry Alumina Scrubbers unit (See Cost Effectiveness and Cost Estimate Spreadsheets in Appendix A).

5.2 Clean Air Act Regulations Controlling Aluminum Production Facilities

The 1999 RH Rule was issued to fulfill the requirements of Section 169A and 169B of the CAA. Section 169(B) of the CAA and 40 CFR 51.308 (e)(1)(ii)(B) required states to address the Best Available Retro-fit Technology (BART) requirement when developing their RH SIPs for the first implementation period. Under the CAA, BART is required for certain large stationary sources that a state determined "emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any Class I area." The potlines at Alcoa were found to be subject to BART according to the criteria outlined in the BART Guidelines, so Alcoa proposed limiting the anode grade coke to 3.5% sulfur to satisfy BART. IDEM approved Alcoa's BART strategy since SO_2 emissions from the potlines can be controlled by limiting the sulfur content in the anode grade coke. The emission limits representing BART for the potlines were included in the first planning period RH SIP. The EPA published the final approval of Indiana's RH SIP for the first implementation period on Oct 7, 2019.

Revised National Ambient Air Quality Standards (NAAQS) have also aided in lowering SO_2 emissions from the potline stacks and roof monitors and anode baking ring furnace at the A-446 Dry Alumina Scrubbers unit; although, SO_2 emission limitations for the Alcoa potlines were already established. The 2008 revised Ozone NAAQS has contributed to the reduction in SO_2 emissions from these emission units, as well. The Potlines and Potlines Support Plant, the Green Anode Plant and the Anode Baking Plant at Alcoa are affected facilities under the NESHAP for Primary Aluminum Reduction Plants, 40 CFR 63, Subpart LL. While the 2008 revised Ozone NAAQS and NESHAP, Subpart LL do not specifically regulate SO_2 emissions from the affected facilities at the Alcoa plant, reducing ozone and toxic air emissions from these combustion sources will also contribute to SO_2 emission reductions.

6.0 ELECTRIC UTILITY SERVICES

6.1 Primary Energy - Cokenergy LLC (Cokenergy) NO_x and SO_2 Emissions and Controls

Cokenergy operates as a contractor at the Cleveland-Cliffs Indiana Harbor Works (CC-IH) facility in East Chicago, Indiana. The facility is a stationary waste heat recovery system for coal carbonization to produce steam and electricity for use at the CC-IH facility. The emission unit identified in IDEM's RFI is listed in the Table 6-1. The unit's source of NO_x and SO_2 emissions and existing control measure(s) are described in this section.

Table 6-1 Cokenergy Emission Units and Pollutants Identified for Four-Factor Analysis

Emission Unit	Applicable Pollutant(s)
Lime Spray Dryer Flue Gas Desulfurization Unit	SO_2

The Cokenergy facility is a first-of-a-kind combined heat and power system that uses the waste heat in the flue gas from Indiana Harbor Coke Company (IHCC), another contractor at the CC-IH facility, metallurgical coke facility to produce steam and power for the CC-IH facility. Cokenergy's sixteen heat recovery steam generators (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 team turbine. With the steam and power generated in this process, Cokenergy supplies electricity as well as high-pressure process steam to CC-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.

6.1.1 Cokenergy Four-Factor Analysis of Potential SO_2 Control Options

In 2014, Cokenergy contracted with an engineering firm to conduct a study to evaluate and optimize the existing FGD system that controls SO_2 emissions from the process. The coke oven flue gas enters the heat recovery steam generators operated by Cokenergy that produce process steam and electricity for the CC-IH facility from heat recovered from the coke ovens. The flue gas is then directed to the FGD system, which consists of two SDAs where the flue gas mixes with sorbent to remove SO_2 then the flue gas goes through two 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. Cokenergy's original FGD system, as installed, consist of the following equipment:

- Sixteen HRSGs, four 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 SDAs for mixing of flue gas with sorbent material to environmentally treat, or remove, SO_2 from the flue gas.
- Two individual sixteen compartment pulse jet, fabric filter baghouses, which removes particulate emissions from the flue gas.
- Two induced draft (ID) fans, which pull draft through the entire flue gas system from the coke ovens to the ID fans.
- One extraction/condensing steam turbine generator (STG). The STG accepts the steam generated by the HRSGs and includes a six-cell cooling tower, boiler feedwater heater and two deaerators.

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. 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 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 are:

- 2010 to 2015 - Retubed all sixteen 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.
- 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 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 6-1 on page 66.

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 overscrubbing 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.
  - 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 injection ratio was achieved by reducing the flue gas volume.
  - SO_2 removal is directly associated with a higher calcium/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 the 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 an 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 Graph 3-2 in the Cokenergy four-factor analysis document attached for reference in Appendix F.
  - SO_2 removal rate is influenced by the relationship between the final flue gas temperatures and moisture content.

The following four 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 emission reductions, increased maintenance, expected chemical usage, and difficulties related to positioning and available footprint.

- One SDA in Operation Scenario - Graph 3-3 in the Cokenergy four-factor analysis document attached for reference in Appendix F.
  - 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 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.
- Two SDAs Operating in Parallel Scenario - Graph 3-4 in the Cokenergy four-factor analysis document attached for reference in Appendix F.

  - 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.
- DSI with Trona with One or Two SDAs in Operation Scenarios - Graph 3-5 in the Cokenergy four-factor analysis document attached for reference in Appendix F.
  - 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.

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

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 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 6-2 on page 66 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-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.

6.1.2 Cost of Compliance for Potential SO_2 Control Options

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.

Cokenergy reviewed the EPA Cost Control Manual Section 5 Chapter 1 - Wet Scrubbers for Acid Gas for SO_2. The EPA cost control 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 electric generating units which disallows the usage of default coal factors (e.g., lignite, subbituminous, anthracite) from the EPA Cost Control Manual.

Representative inputs in the EPA Cost Control 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 Consent Decree negotiations. Conducting an additional cost of compliance analysis at this time using the EPA Cost Control 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 the unit's stack are unnecessary and technically infeasible for all the reasons stated herein.

As demonstrated in Table 6-2 below, the semiannual average control efficiency pre-FGD enhancement was approximately 43% whereas the semiannual average control efficiency post-FGD enhancement was approximately 61%. The equation used to calculate the monthly average SDA SO_2 control efficiencies is shown on the next page.

Table 6-2 Cokenergy Flue Gas Desulfurization SDA SO_2 Control Improvement

Timeframe	Date	Monthly Average Stack SO_2 Emissions (lb./hr)	Monthly Average Bypass Stack SO_2 Emissions (lb/hr)	Monthly Average Total SO_2 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 SO_2 Input to FGD (lb/hr)	Monthly Average SO_2 Input to SDA (lb/hr)	Monthly Average SDA SO_2 Control Efficiency (%)	Semiannual Average SDA SO_2 Control Efficiency (%)
Pre-FGD Enhancement Timeframe	14-Nov	1,413.00	152.00	1,565.00	4,351.00	0.84	2,872.00	61%	3,172.00	3,020.00	49%	43%
	14-Dec	1,529.00	21.00	1,551.00	4,266.00	0.81	2,815.00	60%	2,943.00	2,922.00	46%	
	15-Jan	1,505.00	35.00	1,540.00	3,670.00	0.81	2,454.00	60%	2,501.00	2,466.00	35%	
	15-Feb	1,540.00	15.00	1,555.00	3,707.00	0.80	2,443.00	60%	2,499.00	2,484.00	37%	
	15-Mar	1,414.00	115.00	1,530.00	3,814.00	0.79	2,528.00	59%	2,535.00	2,420.00	42%	
	15-Apr	1,399.00	179.00	1,578.00	4,284.00	0.81	2,753.00	61%	2,985.00	2,805.00	46%	
Post-FGD Enhancement Timeframe	20-Jan	1,175.00	181.00	1,356.00	5,074.00	0.93	3,325.00	71%	3,952.00	3,771.00	64%	61%
	20-Feb	1,175.00	173.00	1,347.00	4,957.00	0.89	3,084.00	73%	3,569.00	3,396.00	60%	
	20-Apr	1,312.00	72.00	1,384.00	4,998.00	0.89	3,315.00	66%	3,736.00	3,664.00	63%	
	20-May	1,364.00	5.00	1,369.00	4,965.00	0.90	3,302.00	68%	3,674.00	3,669.00	60%	
	20-Jun	1,218.00	156.00	1,373.00	4,855.00	0.89	3,177.00	69%	3,561.00	3,404.00	59%	

Note: This table was taken from Cokenergy's "Regional Haze Four-Factor Analysis" submittal attached in Appendix F for reference.

SDA Control Effeciency Calculations

$$\text{Raw } SO_2 \text{ Input to FGD} = [\text{Coal Charge (tons)} \times \text{Coal Sulfur Content (\%)}] -$$

$$[\text{Coal Production (tons)} \times \text{Sulfur Content (\%)}] \times \frac{2000 \text{ lbs}}{\text{Ton}} \times \frac{64 \frac{\text{lbs } SO_2}{\text{lbmol}}}{32 \frac{\text{lbs } S}{\text{lbmol}}} \times \frac{1 \text{ day}}{24 \text{ hours}}$$

$$SO_2 \text{ Input to the SDAs} = \text{Stack } SO_2 \text{ Emissions} - \text{Raw } SO_2 \text{ Input to FGD}$$

$$\text{SDA } SO_2 \text{ Control Efficiency} = 100 \times \frac{SO_2 \text{ Inputs to SDAs} - \text{Stack } SO_2}{\text{Raw } SO_2 \text{ Input to FGD}}$$

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, maintaining critical spare parts in inventory for repairs, and following best practice for equipment start-up and shutdowns.

Cokenergy has been working with Primex 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 and progress towards goals.
  - Obtain data, analyze performance, and interpret change.

  - Identify potential safety, reliability, and efficiency issues.
  - Perform first layer of troubleshooting.
  - Provide actions and recommendations.
  - Hold conference call with Cokenergy team to review findings.
- Quarterly tasks completed by Primex
  - Analyze pebble lime and lime slurry samples.
  - Hold on-site meeting with Cokenergy team.
  - Identify and agree on improvement opportunities.
  - Prioritize actions and assignment of resources.
  - Update strategy and action plan.
- Current action plan between Cokenergy and Primex
  - Evaluate the inlet temperature effects on SDA residence calculation.
  - Determine the best method to automatically control approach temperature based on atomizer(s) conditions.
  - Evaluate:
    - Sorbent preparation control system.
    - Long-term ash moisture testing options for approach temperature control.

6.1.3 Cokenergy Reasonable Level of Control for SO_2 Emissions

A cost of compliance analysis was not conducted for Cokenergy's four-factor analysis 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.

7.0 Clean Air Act Regulations Controlling Electric Services Facilities

While there are no Federal regulations that specifically target SO_2 emissions from electric services operations, the revised 2008 Ozone and 2010 one-hour primary SO_2 NAAQS updates have contributed to reductions in SO_2 emissions from the Cokenergy facility. Cokenergy is located in Lake County Indiana. On June 11, 2012, the EPA designated Lake County nonattainment, for the 8-hour ozone standard. SO_2 emissions are controlled by emission limitations established in Indiana's Sulfur Dioxide Rule 326 IAC 7, Lake County Sulfur Dioxide Emission Limitations (326 IAC 7-4.1-7). In addition, a Consent Decree, Civil Action No. 18cv-35, issued November 30, 2001 established some additional operating limitations and monitoring requirements related to SO_2 that were incorporated into the source's Title V Operating permit and currently remain in place.

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Appendix A

Four-Factor Analysis Cost Estimate and Effectiveness

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Cleveland Cliffs Indiana Harbor East

NO_x and SO_2 Control Cost Analysis for Walking Beam Furnace and Sinter Plant Windbox

Cost Detail Description	NO_x Controls		Sinter Plant Windbox	
	Ultra Low NO_x Burners		SO_2 Controls	
	WBF #5	WBF #6	Spray Dryer Absorber	Dry Sorbent Injection
Equipment	1,111,000	1,111,000		
Installation	2,287,000	2,287,000		
Total Direct Capital Cost (DCC)	3,398,000	3,398,000		
Total Indirect Capital Cost (IOC)	550,200	550,200		
Total Capital Investment (TCI)	5,133,000	5,133,000	56,004,757	56,004,757
Total Direct Operating Costs	82,500	82,500	2,203,032	2,203,032
Total Indirect Operating Costs	684,300	684,300	7,448,000	7,448,000
Total Annual Costs	766,800	766,800	9,651,032	9,651,032

The detailed cost estimates for the reasonable set of emission control measures can be found in ArcelorMittal's submittal "Regional Haze Four-Factor Analysis with Visibility Benefits Evaluation for NO_x and SO_2 Emissions Control for Indiana Harbor East attached in Appendix B.

Operating Company: Cleveland Cliffs Steel
Facility: Indiana Harbor East
State: Indiana

NO_x and SO_2 Controls

Control Cost Summary	80" Hot Strip Mill Walking Beam Furnaces Low-NOx Burners NO_x Controls		Sinter Plant Windbox SO_2 Controls	
	WBF #5	WBF #6	Spray Dryer Absorber	Dry Sorbent Injection
Total Capital Cost	$5,133,000	$5,133,000	37,871,432	30,433,986
Total Annual Cost (Capital & Operating)	$766,800	$766,800	$9,651,032	$9,651,032
Current Emissions (ton/yr)	214	236.6	371	371
Control Efficiency	39%	46%	90%	70%
New Emission Rate (tons/yr)	131	127	37	111
Emission Reductions (tons/yr)	83	110	334	260
Cost-Effectiveness ($/ton)	9,300	7,000	28,900	38,200

Note: Cost-Effectiveness ($/ton) = Total Annual Cost/New Emission Rate (the cost effectiveness number shown in the table reflects the numbers provided in ArcelorMittal's submittal "Regional Haze Four-Factor Analysis with Visibility Benefits Evaluation for NO_x and SO_2 Emissions Control" for Indiana Harbor East attached in Appendix B.

Cleveland Cliffs Burns Harbor

SO_2 Control Cost Analysis for Spray Dryer Absorber on Battery Nos. 1 and 2; Spray Dryer Absorber and Dry Sorbent Injection on Power Station Boilers; and Coke Oven Gas Desulfirization on Clean Coke Oven Gas Export Line

Control Cost Summary	Battery No. 1	Battery No. 2	Clean Coke Oven Gas Export Line and Flare	Power Station Boilers											
				No. 7		No. 8		No. 9		No. 10		No. 11		No. 12	
	Spray Dryer Absorber	Spray Dryer Absorber	Coke Oven Gas Desulfurization	Spray Dryer Absorber	Dry Sorbent Injection	Spray Dryer Absorber	Dry Sorbent Injection	Spray Dryer Absorber	Dry Sorbent Injection	Spray Dryer Absorber	Dry Sorbent Injection	Spray Dryer Absorber	Dry Sorbent Injection	Spray Dryer Absorber	Dry Sorbent Injection
Equipment	28,530,312	25,769,315		39,881,082	9,080,638	39,881,082	7,757,623	39,881,082	7,547,825	39,881,082	7,546,432	39,881,082	7,453,627	39,881,082	8,476,187
Installation	21,112,431	19,069,293		29,512,001	6,719,672	29,512,001	5,740,641	29,512,001	5,585,391	29,512,001	5,584,359	29,512,001	5,515,684	29,512,001	6,272,379
Total Direct Capital Cost (DCC)	49,642,743	44,838,608		69,393,083	15,800,310	69,393,083	13,498,264	69,393,083	13,133,216	69,393,083	13,130,791	69,393,083	12,969,311	69,393,083	14,748,566
Total Indirect Capital Cost (IOC)	14,835,762	13,400,044		20,738,163	4,721,932	20,738,163	13,400,044	20,138,763	3,924,869	20,738,163	3,924,144	20,738,163	3,875,886	20,738,163	4,407,617
Total Capital Investment (TCI)	64,282,882	58,061,815		89,645,479	20,522,242	89,754,364	17,155,347	90,131,245	16,690,046	89,745,523	16,669,213	89,774,258	16,488,210	89,690,262	18,715,200
Total Direct Operating Costs	1,313,341	1,345,217		1,566,988	2,706,554	1,269,063	2,081,855	1,204,881	1,832,253	1,166,516	1,502,284	1,195,479	1,872,475	1,408,712	2,271,859
Total Indirect Operating Costs	8,213,753	7,437,372		11,458,125	2,848,930	11,431,233	2,452,235	11,429,049	2,391,409	11,433,416	2,395,387	11,426,319	2,362,350	11,447,064	2,668,916
Total Annual Costs	9,527,094	8,782,589	27,854,000	13,025,113	5,555,484	12,700,296	4,534,089	12,633,930	4,223,662	12,599,932	3,897,671	12,621,798	4,234,824	12,855,776	4,940,775

The detailed cost estimates for the reasonable set of emission control measures can be found in ArcelorMittal's submittal "Regional Haze Four-Factor Analysis with Visibility" Benefits Evaluation for NO_x and SO_2 Emissions Control" for Burns Harbor in Appedix D.

Operating Company: Cleveland Cliffs Steel
Facility: Burns Harbor
State: Indiana

SO_2 Controls

Control Cost Summary	Battery No. 1	Battery No. 2	Export Line and Flare	Power Station Boilers											
				No. 7		No. 8		No. 9		No. 10		No. 11		No. 12	
	Spray Dryer Absorber	Spray Dryer Absorber	Coke Oven Gas Desulfurization	Spray Dryer Absorber	Dry Sorbent Injection	Spray Dryer Absorber	Dry Sorbent Injection	Spray Dryer Absorber	Dry Sorbent Injection	Spray Dryer Absorber	Dry Sorbent Injection	Spray Dryer Absorber	Dry Sorbent Injection	Spray Dryer Absorber	Dry Sorbent Injection
Total Capital Cost	$64,282,882	$58,061,815	CBI	$89,645,479	$20,036,476	$89,754,364	$17,155,347	$89,763,206	$16,690,046	$89,745,523	$16,669,213	$89,774,258	$16,488,210	$89,690,262	$18,715,200
Total Annual Cost (Capital & Operating)	$9,527,094	$8,782,589	$27,854,000	$13,025,113	$5,555,484	$12,700,296	$4,534,089	$12,633,930	$4,223,662	$12,599,932	$3,897,671	$12,621,798	$4,234,824	$12,855,776	$4,940,775
Current Emissions (ton/yr)	1,675	1,854	8,096	901	901	651	651	524	524	334	334	554	554	703	703
Control Efficiency	90%	90%	86%	90%	70%	90%	70%	90%	70%	90%	70%	90%	70%	90%	70%
New Emission Rate (tons/yr)	167	185	1,099	90	270	65	195	52	157	33	100	55	166	70	211
Emission Reductions (tons/yr)	1,507	1,668	6,997	811	631	586	456	472	367	300	233	499	388	633	492
Cost-Effectiveness ($/ton)	6,300	5,300	4,000	16,100	8,800	21,700	9,900	26,800	11,500	42,000	16,700	25,300	10,900	20,300	10,000

Note: Cost-Effectiveness ($/ton) = Total Annual Cost/New Emission Rate (the cost effectiveness numbers shown in the tables below reflect the numbers provided in ArcelorMittal's submittal
"Regional Haze Four-Factor Analysis with Visibility Benefits Evaluation for NO_x and SO_2 Emissions Control" for Burns Harbor attached in Appendix D.

US Steel Gary Works

NO_x Control Cost Analysis for Low-NO_x Burners on 84" Hot Strip Mill Reheat Furnaces 1 - 4 and Waste Heat Boiler No. 1 and 2

Cost Detail Description	Low-NO_x Burners		
	84" Hot Strip Mill Reheat Furnaces 1 - 4	Waste Heat Boiler No. 1	Waste Heat Boiler No. 2
Equipment	6,100,000	492,800	492,800
Installation	10,000,000	660,000	660,000
Total Direct Capital Cost (DCC)	16,100,000	1,152,800	1,152,800
Total Indirect Capital Cost (IOC)	6,910,000	653,940	653,940
Total Capital Investment (TCI) = DC + IC	23,010,000	1,806,740	1,806,740
Total Direct Operating Costs	82,450	82,450	82,450
Total Indirect Operating Costs	2,895,331	272,926	272,926
Total Annual Costs	2,977,781	355,376	355,376

The detailed cost estimates for the reasonable set of emission control measures can be found in US Steel's submittal "Regional Haze Four-Factor Analysis with Visibility" Benefits Evaluation for NO_x and SO_2 Emissions Control" for Gary Works in Appedix E.

Operating Company: United States Steel Corporation

Facility: Gary Works

State: Indiana

NO_x Controls

Control Cost Summary	Low-NO_x Burners		
	84” Hot Strip Mill Reheat Furnaces 1 - 4	Waste Heat Boiler No. 1	Waste Heat Boiler No. 2
Total Capital Cost	$23,010,000	$1,806,740	$1,806,740
Total Annual Cost (Capital & Operating)	$2,977,781	$355,376	$355,376
Current Emissions (ton/yr)	323	89	86
Control Efficiency	65%	65%	65%
New Emission Rate (tons/yr)	113	31	30
Emission Reductions (tons/yr)	211	58	56
Cost-Effectiveness ($/ton)	14,142	6,130	6,344

Note: Cost-Effectiveness ($/ton) = Total Annual Cost/New Emission Rate (the cost effectiveness numbers shown in the table reflect the numbers provided in US Steel's submittal

"Regional Haze Four-Factor Analysis with Visibility Benefits Evaluation for NO_x and SO_2 Emissions Control" for Gary Works attached in Appendix E.

SABIC Mt. Vernon

NO_x Control Cost Analysis for SCR on COGEN

Design Parameters			
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/yr
Actual Annual fuel consumption (Mactual) =		12,643,340,488	scf/yr
Heat Rate Factor (HRF) =	NPHR/10 =	0.82	
Total System Capacity Factor (CFtotal) =	(Mactual/Mfuel) x (t_{scr}/tplant) =	0.816	fraction
Total operating time for the SCR (top) =	CFtotal x 8760 =	7152	hours
NOx Removal Efficiency (EF) =	(NO_{xin} - NO_{xout})/NO_{xin} =	85	percent
NOx removed per hour =	NO_{xin} x EF x Q_B =	28.33	lb/hr
Total NOx removed per year =	(NO_{xin} x EF x Q_B x top)/2000 =	101.30	tons/yr
NOx removal factor (NRF) =	EF/80 =	1.06	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x Q_B x (460 + T)/(460 + 700)$_{nscr}$ =	818,037.00	acfm
Space velocity (Vspace) =	qflue gas/Volcatalyst =	110.00	
Space velocity (Vspace) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	110.00	
Residence Time	1/Vspace	0.01	/hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for subbituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	hour
SO2 Emission rate =	(%S/100) x (64/32)*1x106)/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 x [(59 -(0.00356 x h) + 459.7)/518.6]5.256 x (1/144)* =	13.90	psia
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00	
* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.			
Catalyst Data			
Parameter	**Equation**	**Calculated Value**	**Units**
Future worth factor (FWF) =	(interest rate)(1/((1 + interest rate)Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer)	0.3157	fraction
Catalyst volume (Volcatalyst) =	2.81 x Q_B x EF adj x $Slip_{adj}$ x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	7,437.61	cubic feet
Cross sectional area of the catalyst (Acatalyst) =	$q_{flue\ gas}$ /(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 =	$(A_{SCR})^{0.5}$	7,437.61	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	852	feet
Reagent Data			
		Molecular Weight of Reagent (MW) =	17.03 g/mole
Type of reagent used	Ammonia	Density =	56 lb/ft^3
Parameter	**Equation**	**Calculated Value**	**Units**
Reagent consumption rate ($m_{reagent}$) =	(NO_{xin} x Q_B x EF x SRF x MW_R)/$MWNO_x$ =	11	
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/C_{sol} =	38.00	
	(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		
Electricity Usage			
Other Parameters	**Equation**	**Calculated Value**	**Units**
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(\text{CoalF x HRF})^{0.43}$ =	931.72	kW
	Where A = (0.1 x Q_B) for industrial boilers.		
Cost Estimate			
Total Capital Investment (TCI) for Oil and Natural Gas Boilers			
For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:			
	TCI = 86,380 x (200/BMW)0.35 x BMW x ELEVF x RF		
For Oil and Natural Gas-Fired Utility Boilers >500 MW:			
	TCI = 62,680 x BMW x ELEVF x RF		
For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :			
	TCI = 7,850 x $(2,200/Q_B)^{0.35}$ x Q_B x ELEVF x RF		
For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :			
	TCI = 10,530 x $(1,640/Q_B)^{0.35}$ x Q_B x ELEVF x 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

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 =	msol x $Cost_{reag}$ x top =	\$10,628 in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x top =	\$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

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/NO_x Removed/Year

Total Annual Cost (TAC) =	\$2,602,806 in 2019 dollars
NO_x Removed =	101 tons/yr
Cost Effectiveness =	\$25,691 per ton of NO_x removed in 2019 dollars

Operating Company: SABIC
Facility: Mt. Vernon
State: Indiana

NO_x Controls

Control Cost Summary	COGEN SCR
Total Capital Cost	$21,805,180
Total Annual Cost (Capital & Operating)	$2,602,806
Current Emissions (ton/yr)	119
Control Efficiency	83%
New Emission Rate (tons/yr)	18
Emission Reductions (tons/yr)	101
Cost-Effectiveness ($/ton)	25,691

Note: Cost-Effectiveness ($/ton) = Total Annual Cost/New Emission Rate (the cost effectiveness numbers shown in the tables below reflect the numbers provided in SABIC's submittal "Regional Haze Four-Factor Analysis with Visibility Benefits Evaluation for NO_x and SO_2 Emissions Control" for Mt. Vernon attached in Appendix F.

SABIC Mt. Vernon

SO_2 Cost Estimate and Cost Effectiveness for Wet Packed Tower Gas Absorber on COS Vent Scrubber

Capital Cost Summary (See Reference Notes Below)

References	Cost Detail	Notes	Costs	References
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	
Ref.	*Operation and Maintenance Costs Table*			*Ref*
	Annual Costs			
2a, 6	Ref. Operation and Maintenance Costs Table Ref	0.5 hr/shift * 3 shifts/day * $/hr	$21,920	Table 1.8
2a, 6	Operating Labor	15% of operator labor	$3,288	Table 1.8
2a, 6	Supervisor Labor	0.5 hr/shift * 3 shifts/day * $/hr	$29,044	Table 1.8
2a, 6	Maintenance Labor	100% of maintenance labor	$29,044	Table 1.8
2a	Maintenance Materials			
Ref.	*Cost of Solvent/Reagent (Sodium Hydroxide NaOH)*			
	Total Annual NaOH Usage	tons/yr	975	
	Unit cost	$/ton	$385.49	
	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	$62,244	
Ref.	*Auxiliary Power Costs*			
3	Power Required	kW	24	
3	Hours Operated	top	6,340	
8	Unit cost	$/kW-hr	$0.07	
2a	Total	kW * $/kWh * top	$11,079	
	Direct Annual Cost (DAC)		**$532,580**	
				Table / Equation
Ref.	*Indirect Annual Cost*			*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	0.02 * TCI	$511,098	Table 1.8
2a	Insurance	0.02 * 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 / Equation
Ref.	*Parameter*			*Ref.*
3	Baseline SO_2 Emissions	tons/yr	570	
3	Control Efficiency		95%	
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
2a	Cost Effectiveness	$/ton removed	$12,449	Equation 1.31

References:

1 TCI is derived using the cost for a similar wet packed tower gas absorber (i.e., scrubber) completed at Mt. Vernon in 2010. Mt. Vernon 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, Mt. Vernon 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 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/.

Operating Company: SABIC
Facility: Mt. Vernon
State: Indiana

NO_x Controls

Control Cost Summary	COS Vent Scrubber
	Gas Absorber
Total Capital Cost	$46,339,513
Total Annual Cost (Capital & Operating)	$6,745,699
Current Emissions (ton/yr)	570
Control Efficiency	95%
New Emission Rate (tons/yr)	29
Emission Reductions (tons/yr)	542
Cost-Effectiveness ($/ton)	12,449

Note: Cost-Effectiveness ($/ton) = Total Annual Cost/New Emission Rate (the cost effectiveness number shown in the table reflect the numbers provided in SABIC's submittal "Regional Haze Four-Factor Analysis with Visibility Benefits Evaluation for NO_x and SO_2 Emissions Control" for Mt Vernon attached in Appendix F.

Operating Company: Alcoa

Facility: Warrick

State: Indiana

SO_2 Controls

Control Cost Summary	Potlines 2-6	Anode Baking Ring Furnace & A-446 Dry Alumina Scrubbers
	Flue Gas Desulfurization	Flue Gas Desulfurization
Total Capital Cost	$512,800,000	$63,900,000
Total Annual Cost (Capital & Operating)	$5,300,000	$700,000
Current Emissions (ton/yr)	3,000	139
Control Efficiency	70%	70%
New Emission Rate (tons/yr)	900	42
Emission Reductions (tons/yr)	2,100	97
Cost-Effectiveness ($/ton)	2,524	7,194

Note: Current emissions for the Alcoa potlines were estimated using the highest reported emissions of the three potlines that operated in 2018 for all five units (600 tons x 5 potlines).

Appendix B

Indiana Harbor East Four-Factor Analysis Submittal

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ArcelorMittal USA LLC
Indiana Harbor East

ArcelorMittal

September 30, 2020

BY ELECTRONIC MAIL ONLY

Ms. Jean Boling
Senior Environmental Engineer
Indiana Department of Environmental Management
Office of Air Quality, Room 1003
100 North Senate Avenue
Indianapolis, IN 46204-2251
jboling@idem.IN.gov

Re: ArcelorMittal USA LLC – Indiana Harbor East Facility (-00316)
Regional Haze State Implementation Plan Second Planning Period
Four-Factor Analysis Report

Dear Ms. Boling,

ArcelorMittal USA LLC is timely submitting the enclosed Four-Factor Analysis Report for the Indiana Harbor East facility in response to the Indiana Department of Environmental Management's (IDEM's) June 18, 2020 Request for Information (RFI) Letter in support of the State's work on the second planning period state implementation plan (SIP) revisions for Regional Haze (RH).

If there are any questions, please contact me at (219) 399-1091.

Sincerely,

Tom Maicher

Tom Maicher
ArcelorMittal USA LLC – Indiana Harbor East

Enclosure

cc: Mark Derf, IDEM Office of Air Quality
Scott Deloney, IDEM Office of Air Quality
Rich Zavoda, ArcelorMittal USA

Regional Haze Four-Factor Analysis with Visibility Benefits Evaluation for NO_X and SO_2 Emissions Control

- ***No. 4 Basic Oxygen Furnace***
- ***No. 5 Boiler House Boilers 501-504***
- ***No. 7 Blast Furnace Stoves, Casthouse and Flares***
- ***Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns***
- ***80" Hot Strip Mill Walking Beam Furnaces #4-#6***
- ***Sinter Plant Windbox***

Prepared for
ArcelorMittal USA, LLC
Indiana Harbor East Facility

September 30, 2020

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Regional Haze Four-Factor Analysis with Visibility Benefits Evaluation for NO_X and SO_2 Emissions Control

September 30, 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
AOI	Area of Influence
BACT	best available control technology
Barr	Barr Engineering
BART	best available retrofit technology
BOF	Basic Oxygen Furnace
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
HSM	Hot Strip Mill
IDEM	Indiana Department of Environmental Management
IHE	ArcelorMittal Indiana Harbor East
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
ULNB	Ultra Low-NO_X Burners
URP	Universal Rate of Progress
VISTAS	Visibility Improvement State and Tribal Association of the Southeast
WBF	Walking Beam Furnace

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 Indiana Harbor East (IHE) evaluated potential emission control measures for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) emissions for the No. 5 Boiler House Boilers 501-504; No. 7 Blast Furnace Stoves, Casthouse and Flares; Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns; and Sinter Plant Windbox. IHE evaluated potential emission control measures for NO_X emissions for the No. 4 Basic Oxygen Furnace and 80" Hot Strip Mill (HSM) Walking Beam Furnaces (WBFs) #4-#6[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. IHE reserves the right to amend and/or supplement this report and analysis once CAMx modeling has been completed.

The four-factor analyses with visibility benefits evaluations for the No. 4 Basic Oxygen Furnace (NO_X, Section 3.1), the No. 5 Boiler House Boilers 501-504 (NO_X, Section 4.1; SO_2, Section 4.2), the No. 7 Blast Furnace Stoves, Casthouse, and Flares (NO_X, Section 5.1; SO_2, Section 5.2), the Lime Plant Nos. 1 and 2 Kilns and Preheater (NO_X, Section 6.1; SO_2, Section 6.2), and the 80" HSM #4 WBF (NO_x, Section 7.1.1) concluded that:

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[1] June 18, 2020 letter from Mathew Stuckey of IDEM to Thomas Maicher of ArcelorMittal USA, LLC.

[2] IDEM's RFI included 80" HSM rolling mill operations and, on June 19, 2020, IDEM clarified this was referring to any other high-emitted NO_X or SO_2 units associated with that operation. This is not applicable because there are no other NO_X or SO_2 emitting sources associated with the 80" HSM besides the WBFs.

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

- 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 and SO_2 emission control measures is not technically feasible for these emission units.

- Therefore, the existing NO_X and SO_2 emission performance for these emission units are sufficient for the IDEM's regional haze reasonable progress goal.

As described in Section 7, the 80" HSM #5 and #6 WBF 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 Ultra Low-NO_X Burners (ULNB)[4] for #5 and #6 WBFs.

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

- Independent of the four-factor analysis, additional NO_X emission reductions are not appropriate and are unnecessary for the #5 and #6 WBFs 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, 499 km), Seney National Wildlife Refuge (Seney, 513 km), and Isle Royale National Park (Isle Royale, 699 km)), or trending towards and expected to attain without additional emission reductions (Mingo National Wildlife Refuge (Mingo, 561 km)), the 2028 Universal Rate of Progress (URP) (see Section 9.1), and

    - The visibility impacts analysis completed to date indicates that IHE is not a contributor to perceptible[5] visibility impairment to the Class I areas on the most impaired days, thus any installation of additional emission control measures at IHE 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 9.3). Further analysis through CAMx modeling that is underway is anticipated to confirm that IHE does not have a perceptible visibility impact on these Class I areas. IHE reserves the right to amend and/or supplement this report and visibility analysis once CAMx modeling has been completed.

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[4] Induced flue gas recirculation burners, also referred to as ULNB, combine the principles of flue gas recirculation and low-NO_X burner control technologies. The burner draws flue gas to dilute the fuel and utilize staged fuel combustion to reduce the flame temperature and thermal NO_X formation.

[5] 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)

- Therefore, the 80” Hot Strip Mill #5 and #6 WBFs existing NO_X emission performances are sufficient for the IDEM’s regional haze reasonable progress goal.

As described in Section 8, the Sinter Plant Windbox NO_X and SO_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 Sinter Plant Windbox. There is no available set of additional NO_X emission control measures for this emission unit.
- The reasonable set of SO_2 emission control measures beyond what is currently installed and operated for this emission unit consists of spray dryer absorbers[6] and dry sorbent injection[7].
- 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 80” Hot Strip Mill #4, #5, and #6 WBFs conclusion above, additional NO_X and SO_2 emission reductions are not appropriate and are unnecessary for the Sinter Plant Windbox, independent of the four-factor analysis, because IHE 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 9).
- Therefore, the Sinter Plant Windbox 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 IHE) from installing additional emission control measures on the associated sources at the facility. An analysis of current visibility conditions was completed for Mammoth Cave (499 km), Mingo (561 km), Seney (513 km) and Isle Royale (699 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 9.1, the 5-year average visibility impairment on the most impaired days is already below the 2028 URP (Mammoth Cave (499 km), Seney (513 km) and Isle Royale (699 km)), or trending towards and

[6] 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.

[7] Dry sorbent (pulverized lime or limestone) is directly injected into the duct upstream of a 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.

expected to attainment to the 2028 URP (Mingo (561 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 IHE 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 (499 km), Mingo (561 km), Seney (513 km) and Isle Royale (699 km)) to determine how emissions from IHE could impact visibility in Class I areas on the 20% most impaired days. As shown in Section 9.3.1, 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 IHE because the visibility impacts were less than the screening thresholds which were applied (see Section 9.3.2). Additionally, a back-trajectory analysis was conducted for Seney (513 km) and Isle Royale (699 km) that demonstrates emission reductions at IHE are unlikely to improve visibility on the most impaired days at these Class I areas (see Section 9.3.3). Finally, further analysis through CAMx modeling that is underway is anticipated to confirm that IHE does not have a perceptible visibility impact on these Class I areas. IHE 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	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. 4 Basic Oxygen Furnace						
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. 5 Boiler House Boilers 501-504						
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. 7 Blast Furnace Stoves, Casthouse, and Flares						
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.
Lime Plant Nos. 1 and 2 Kilns and Preheater						
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.
80" HSM #4 WBF						
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.
80" HSM #5 and #6 WBFs						
ULNB	#5 WBF = $9,300 per ton of NO_x removed #6 WBF = $7,000 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 IHE would not improve visibility at Class I areas of interest on the most impaired days.	No – ULNB's cost of compliance are not reasonable because they would not improve the visibility at the associated Class I areas of interest on the most impaired days.
Sinter Plant Windbox						
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	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. 5 Boiler House Boilers 501-504						
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. 7 Blast Furnace Stoves, Casthouse, and Flares						
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.
Lime Plant Nos. 1 and 2 Kilns and Preheater						
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.
Sinter Plant Windbox						
Spray Dryer Absorber	$28,900 per ton of SO_2 removed	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. -Increased fuel use for process gas duct heaters to evaporate spray dryer moisture. Environmental -Additional solid waste generation and disposal.	20-year control equipment life	Emissions reductions at IHE would not improve visibility at Class I areas of interest on the most impaired days.	No – A Spray Dryer Absorber's cost of compliance is not reasonable because it would not improve the visibility at the associated Class I areas of interest on the most impaired days.
Dry Sorbent Injection	$38,200 per ton of SO_2 removed	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 IHE 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 because it would not improve the visibility at the associated Class I areas of interest on the most impaired days.

2 Introduction

Barr Engineering (Barr) was asked to prepare this four-factor analysis to determine the effect of IHE on visibility at the applicable Class I areas, as well as determine whether additional emission control measures at identified IHE units are necessary and reasonable in order to achieve reasonable progress towards national visibility goals. Section 2.1 discusses the RFI provided to IHE 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 IHE 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 IHE 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
No. 4 Basic Oxygen Furnace (BOF)	NO_X
No. 5 Boiler House Boiler 501	NO_X, SO_2
No. 5 Boiler House Boiler 502	NO_X, SO_2
No. 5 Boiler House Boiler 503	NO_X, SO_2
No. 5 Boiler House Boiler 504	NO_X, SO_2
No. 7 Blast Furnace Stoves, Casthouse and Flare	NO_X, SO_2
Lime Plant No. 1 Preheater and Rotary Kiln	NO_X, SO_2
Lime Plant No. 2 Preheater and Rotary Kiln	NO_X, SO_2
80" Hot Strip Mill #4 Walking Beam Furnace	NO_X
80" Hot Strip Mill #5 Walking Beam Furnace	NO_X
80" Hot Strip Mill #6 Walking Beam Furnace	NO_X
Sinter Plant Windbox	NO_X, SO_2

Note: IDEM's RFI included 80" HSM rolling mill operations and, on June 19, 2020, IDEM clarified this was referring to any other high-emitted NO_X or SO_2 units associated with that operation. This is not applicable because there are no other NO_X or SO_2 emitting sources associated with the 80" HSM besides the WBFs.

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 (499 km), Mingo (561 km), Seney (513 km) and Isle Royale (699 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, 4.1.1, 4.2.1, 5.1.1, 5.2.1, 6.1.1, 6.2.1, 7.1.1, 8.1.1, and 8.2.1. 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, IHE then evaluated these emission control 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, IHE 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

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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.")

provided limited and dated information; the most recent pertinent information for many 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.
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 IHE facility to review potential emission control measures, discuss technical feasibility, and compare to the current configuration.

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

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

[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.

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 emission control measures at IHE would not improve visibility at the associated Class I areas (as described in Section 9.3). 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 some Class I areas is already below the 2028 URP glidepath and some facilities are already committed to additional emission reductions (as described in Section 9.1).

2.1.1.3 Factor 2 – Time Necessary for Compliance

Factor #2 considers the time needed for IHE 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, IHE 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.

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[15] Ibid.

[16] Ibid, Page 36.

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.

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 (499 km), Seney (513 km) and Isle Royale (699 km)), or trending towards and expected to attain without additional emission reductions (Mingo (561 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

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

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

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

2.2.1 No. 4 Basic Oxygen Furnace

The No. 4 Basic Oxygen Furnace (BOF) charges molten iron from the blast furnaces, flux, alloys, and scrap with high-purity oxygen. This process oxidizes or removes excess carbon, silicon, manganese, and other impurities from the hot metal to produce molten steel. When the temperature and composition are satisfactory, the molten steel is tapped into a transfer ladle for subsequent processing. The BOF off-gas is routed to a wet scrubber.

NO_x emissions are generated from atmospheric nitrogen in proximity with the combustion of carbon upon contact with the high-purity oxygen injection. These emissions are assumed to be primarily thermal NO_x.

2.2.2 No. 5 Boiler House Boilers 501-504

The No. 5 Boiler House Boilers 501-504 produce utility steam for operating turbo-blowers in the generation of cold blast (wind) to the blast furnace, high pressure steam for power generation at the turbine, and low pressure steam for use throughout the IHE facility. Each boiler predominantly fires blast furnace gas and automatically supplements natural gas to maintain BFG header pressure. Additionally, NG is occasionally used for flame stability during periods of blast furnace startup/shutdown/low heating value.

The No. 5 Boiler House Boilers 501-504 generate NO_X emissions from natural gas and blast furnace gas 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 No. 5 Boiler House Boilers 501-504 utilize low-NO_X fuel and good combustion practices as NO_X emission control measures.

The No. 5 Boiler House Boilers 501-504 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 No. 7 Blast Furnace Stoves, Casthouse and Flares

The No. 7 Blast Furnace combines 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 and supplemental 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 particulate matter (PM) via the integrated scrubbing system prior to combustion as a fuel source to offset purchased fuels and improve energy efficiency. A flare combusts excess blast furnace gas that is not utilized by the downstream units.

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 No. 7 Blast Furnace Stoves resulting NO_X emissions are generated from primarily firing blast furnace gas and enriched oxygen (with occasional natural gas enrichment) 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 No. 7 Blast Furnace Stoves is an existing NO_X emission control measure.

The No. 7 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_X emissions from the No. 7 Blast Furnace Casthouse are not significant (50.42 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 No. 7 Blast Furnace Casthouse's 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 No. 7 Blast Furnace Flares produce NO_x and SO_2 due to the combustion of blast furnace waste gas and a natural gas pilot. 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.

2.2.4 Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns

The No. 1 and No. 2 Lime Plants produce lime for use throughout the facility. Lime is produced through thermal decomposition of limestone in rotary kilns, where calcium carbonate decomposes into calcium oxide and waste carbon dioxide at temperatures in excess of 1800°F. The kilns are fired with natural gas or residual fuel oil. PM emissions from these sources are controlled with a set of cyclone separators and two baghouses.

The Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns generate NO_X emissions from natural gas and fuel oil combustion. The preheater utilizes residual heat from the rotary kiln combustion gases to preheat limestone feed. This increased energy efficiency results in less fuel usage, and less NO_x emissions as a result. The use of a preheater is a NO_X emission control measure for Lime Plant No. 1 and No. 2.

The Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns generate SO_2 emissions from natural gas and fuel oil combustion. Natural gas is the primary fuel source and is considered a low-sulfur fuel, compared to other solid and liquid fuels, and is utilized as a SO_2 emission control measure. The use of a preheater to preheat limestone feed using residual heat in combustion gases reduces natural gas SO_2 emissions by reducing fuel requirements. Furthermore, the production of lime that is in contact with combustion gases inherently scrubs combustion gases of SO_2, further reducing SO_2 emissions from the unit.

2.2.5 80" Hot Strip Mill Walking Beam Furnaces #4-#6

The 80" Hot Strip Mill WBFs #4-#6 heat incoming steel slabs to working temperatures for downstream mill operations. The reheat furnaces fire natural gas only and the combustion gasses are in direct contact with the steel slabs.

The 80" Hot Strip Mill WBFs #4-#6 generate NO_X emissions from natural gas combustion and follow good combustion practices as a NO_X emission control measure. The #4 WBF is equipped with ULNB as a NO_X emission control measure.

2.2.6 Sinter Plant Windbox

The Sinter Plant agglomerates iron ore fines and other recycled materials from various sources to create a raw material feedstock for the blast furnaces. The sinter feedstocks are blended together (called burden), the surface is ignited within an furnace, and the solid fuel in the blend is combusted by drawing air through the bed of material, sintering the material together while the combustion products are pulled into the Windboxes. The Windboxes exhaust to a multiclone and baghouse to control PM emissions. Sintered material is then cooled, sized, and screened.

Along the traveling grate, the iron ore fines, coke breeze, and other recycled material fines are ignited with natural gas burners. The NO_X emissions are generated from the associated combustion of the solid fuels in the sinter burden and natural gas. The Sinter Plant follows good combustion practices as a NO_X emission control measure.

The Sinter Plant generates SO_2 emissions through oxidation of sulfur compounds present in the raw materials (iron byproduct/recycled materials, coke breeze, etc.) and natural gas fuel. As an SO_2 emission control measure, IHE conducts routine material sampling and adjusts the Sinter Plant feed blend to comply with the Title V Operating Permit SO_2 limit (Permit Condition D.3.3).

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, IHE has achieved substantial facility-wide NO_X and SO_2 emission reductions in the recent years as a result of shut down of operations, including the No. 5 and No. 6 Blast Furnaces, the No. 2 AC Station, the No. 1 Electric Arc Furnace, and the Ladle Metallurgical Facility. Figure 2-1 presents the facility-wide NO_X and SO_2 emissions from 2005 to 2018. IHE has already reduced NO_X and SO_2 emissions by 33% from 2005 (2005 = 7,877 tons/year NO_X and SO_2, 2018 = 5,272 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 9.1) and the lack of visibility impacts at the associated Class I areas from IHE (see Section 9.3). Note, the 2009 emissions reflect an economic downturn that resulted in reduced production rates.

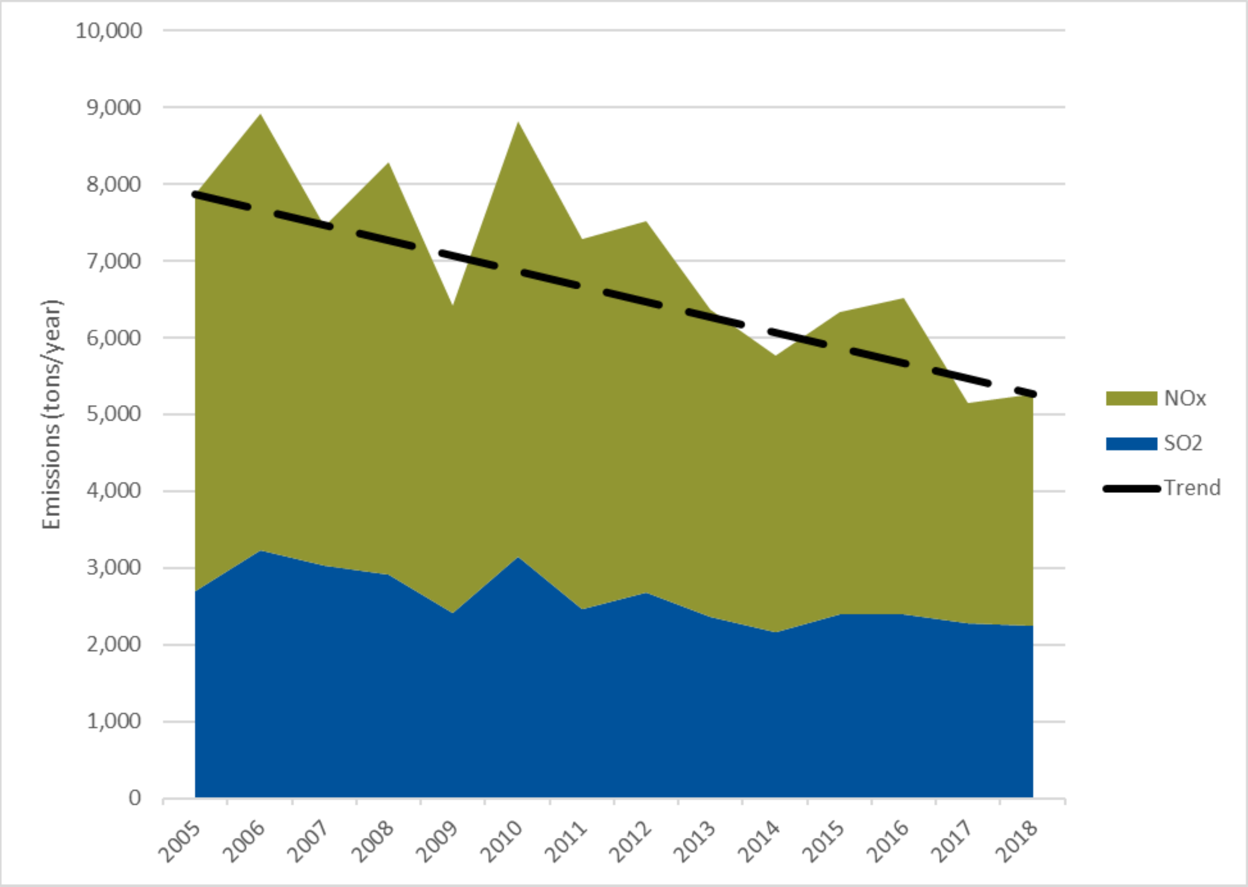

Figure 2-1 Facility-wide NO_X and SO_2 Emissions from 2005 to 2018

3 No. 4 Basic Oxygen Furnace

The following section describes the four-factor analysis with visibility benefits evaluation for NO_X emission control measures for the No. 4 Basic Oxygen Furnace.

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 the No. 4 Basic Oxygen Furnace.

3.1.1 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 Basic Oxygen Furnaces did not identify any NO_X emission control measures.

The RBLC search (Appendix A) listed that no additional NO_X emission control measures were required for a 2005 BACT determination for Wheeling Pittsburgh Steel Corporation (RBLCID = OH-0292).

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 No. 4 Basic Oxygen Furnace 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 the No. 4 Basic Oxygen Furnace has no reasonable set of NO_X emission control measures beyond what is currently installed and operated for this emission unit, 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. 4 Basic Oxygen Furnace has no reasonable set of NO_X emission control measures beyond what is currently installed and operated for this emission unit, 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 the No. 4 Basic Oxygen Furnace has no reasonable set of NO_X emission control measures beyond what is currently installed and operated for this emission unit, 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. 4 Basic Oxygen Furnace has no reasonable set of NO_X emission control measures beyond what is currently installed and operated for this emission unit, 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. 4 Basic Oxygen Furnace has no reasonable set of NO_X emission control measures beyond what is currently installed and operated for this emission unit, 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. 4 Basic Oxygen Furnace has no reasonable set of NO_X emission control measures beyond what is currently installed and operated for this emission unit, 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

The four-factor analysis concluded that additional NO_X emission control measures at the No. 4 Basic Oxygen Furnace 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.

4 No. 5 Boiler House Boilers 501-504

The following sections describes the four-factor analyses with visibility benefits evaluations for NO_X and SO_2 emission control measures for the No. 5 Boiler House Boilers 501-504.

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 No. 5 Boiler House Boilers 501-504.

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)[18], LNB, and ULNB at some sources. As described in Section 2.2.2, the No. 5 Boiler House Boilers 501-504 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 No. 5 Boiler House Boilers 501-504 are not directly comparable to boilers that strictly fire natural gas because the No. 5 Boiler House Boilers 501-504 fire blast furnace gas (a low-NO_X fuel) and supplements with natural gas to maintain flame temperature.

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., blast furnace gas as a primary fuel source).

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 topgas boilers requires the supplement 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 potentially prevent combustion of the fuel from occurring. Thus, Low NO_X burners are not a feasible control technology for the topgas boilers."*[19]

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

[19] Louisiana Department of Environmental Quality, Nucor Steel Permit to Construct (PSD-LA-740) Briefing Sheet, 2010, Page 80.

Since LNB, and by extension ULNB which uses the same principles (longer, cooler flame), represent a negligible or potentially small emission reduction potential, compared to the current NO_X emission control measures, and have potential operational challenges, LNB and ULNB are not considered as part of the reasonable set of NO_X emission control measures for the No. 5 Boiler House Boilers 501-504 and are not evaluated further in this analysis.

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 No. 5 Boiler House Boilers 501-504 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 the No. 5 Boiler House Boilers 501-504 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. 5 Boiler House Boilers 501-504 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 the No. 5 Boiler House Boilers 501-504 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. 5 Boiler House Boilers 501-504 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. 5 Boiler House Boilers 501-504 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. 5 Boiler House Boilers 501-504 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

The four-factor analysis concluded that additional NO_X emission control measures at the No. 5 Boiler House Boilers 501-504 beyond those described in Section 2.2.2 are not required to make reasonable progress. 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 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 No. 5 Boiler House Boilers 501-504.

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 No. 5 Boiler House Boilers 501-504 already utilize low-sulfur fuel combustion (natural gas and blast furnace gas) as an existing SO_2 emission control measure.

There are no additional SO_2 emission control measures beyond what is currently installed and operated for these emission units based on the emission control measures described in the 2010 Nucor BACT, the RBLC (Appendix A), and air permits for II&S mills (Appendix B). As such, the No. 5 Boiler House Boilers 501-504 have no reasonable set of SO_2 emission control measures beyond what is currently installed and operated.

4.2.2 Baseline Emission Rates

Since the four-factor analysis concluded the No. 5 Boiler House Boilers 501-504 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. 5 Boiler House Boilers 501-504 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_2emission control measures.

4.2.4 Factor 2 – Time Necessary for Compliance

Since the four-factor analysis concluded the No. 5 Boiler House Boilers 501-504 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. 5 Boiler House Boilers 501-504 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. 5 Boiler House Boilers 501-504 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. 5 Boiler House Boilers 501-504 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.

4.2.8 Proposed SO_2 Emission Control Measures

The four-factor analysis concluded that additional SO_2 emission control measures at the No. 5 Boiler House Boilers 501-504 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 No. 7 Blast Furnace Stoves, Casthouse and Flares

The following sections describes the four-factor analyses with visibility benefits evaluations for NO_X and SO_2 emission control measures for the No. 7 Blast Furnace.

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 No. 7 Blast Furnace Stoves, Casthouse, and Flares.

5.1.1 NO_X Emission Control Measures

5.1.1.1 No. 7 Blast Furnace 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, the No. 7 Blast Furnace Stoves 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 installed LNB 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"[20]:

> "[…] *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*

[20] 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."[21]

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 the No. 7 Blast Furnace Stoves and are not evaluated further in this analysis.

Therefore, the No. 7 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).

5.1.1.2 No. 7 Blast Furnace Casthouse

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 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 No. 7 Blast Furnace Casthouse has no reasonable set of NO_X emission control measures beyond what is currently installed and operated for this emission unit.

5.1.1.3 No. 7 Blast Furnace Flare

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 No. 7 Blast Furnace Flare has no reasonable set of NO_X emission control measures beyond what is currently installed and operated for this emission unit.

[21] 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 No. 7 Blast Furnace Stoves, Casthouse, 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 No. 7 Blast Furnace Stoves, Casthouse, 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 No. 7 Blast Furnace Stoves, Casthouse, and Flares s 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 No. 7 Blast Furnace Stoves, Casthouse, 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 No. 7 Blast Furnace Stoves, Casthouse, 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 No. 7 Blast Furnace Stoves, Casthouse, 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 No. 7 Blast Furnace Stoves, Casthouse, and Flares beyond those described in Section 2.2.3 are not required to make reasonable progress. 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 No. 7 Blast Furnace Stoves, Casthouse, and Flares.

5.2.1 SO_2 Emission Control Measures

5.2.1.1 No. 7 Blast Furnace 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 No. 7 Blast Furnace 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 No. 7 Blast Furnace 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 No. 7 Blast Furnace Casthouse

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 No. 7 Blast Furnace Casthouse has no reasonable set of SO_2 emission control measures beyond what is currently installed and operated for this emission unit.

5.2.1.3 No. 7 Blast Furnace Flare

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 No. 7 Blast Furnace Flare has no reasonable set of SO_2 emission control measures beyond what is currently installed and operated for this emission unit.

5.2.2 Baseline Emission Rates

Since the four-factor analysis concluded the No. 7 Blast Furnace Stoves, Casthouse, 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 No. 7 Blast Furnace Stoves, Casthouse, 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 No. 7 Blast Furnace Stoves, Casthouse, 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 No. 7 Blast Furnace Stoves, Casthouse, 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 No. 7 Blast Furnace Stoves, Casthouse, 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 No. 7 Blast Furnace Stoves, Casthouse, 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 No. 7 Blast Furnace Stoves, Casthouse, 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 Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns

The following sections describe the four-factor analyses with visibility benefits evaluations for NO_X and SO_2 emission control measures for the Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns.

6.1 Four-Factor Analysis - NO_X

The following sections describe the analysis for determining the reasonable set of NO_X emission control measures (Section 6.1.1), the four-factor analysis with visibility benefits evaluation (Sections 6.1.3 through 6.1.7), and the proposed emission control measures (Section 6.1.8) for the Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns.

6.1.1 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 Lime Plant NO_X emission control measures identified the use of LNB or kiln preheaters at some sources. As described in Section 2.2.4, preheaters are an existing NO_X emission control measure for Lime Plant No. 1 and No. 2. Based on the air permit review (Appendix B), there are no other II&S mills that have on-site lime plants.

IHE identified LNB to be part of the potentially feasible NO_X emission control measures for further evaluation. However, IHE consulted with a burner manufacturer who stated that a low-NO_X burner for burning only natural gas was available but co-firing oil with natural gas presents additional design concerns and they could not guarantee an emission reduction for this technology. Additionally, EPA stated the following in the New Source Review Workshop Manual[22]:

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

Therefore, LNB were not further considered because eliminating oil as an allowable fuel would fundamentally redefine the source and there was no guaranteed emission reduction with a co-fired burner.

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 lime kilns (Appendix B). As such, the Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns have no reasonable set of NO_X emission control measures beyond what is currently installed and operated for these emission units.

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

6.1.2 Baseline Emission Rates

Since the four-factor analysis concluded the Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns 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.

6.1.3 Factor 1 – Cost of Compliance

Since the four-factor analysis concluded the Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns 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.

6.1.4 Factor 2 – Time Necessary for Compliance

Since the four-factor analysis concluded the Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns 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.

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

Since the four-factor analysis concluded the Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns 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.

6.1.6 Factor 4 – Remaining Useful Life of the Source

Since the four-factor analysis concluded the Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns 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.

6.1.7 Visibility Benefits

Since the four-factor analysis concluded the Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns 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.

6.1.8 Proposed NO_X Emission Control Measures

The four-factor analysis concluded that additional NO_X emission control measures at the Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns beyond those described in Section 2.2.4 are not required to make reasonable progress. As such, this analysis proposes to maintain the existing NO_X emission control measures.

6.2 Four-Factor Analysis – SO_2

The following sections describe the analysis for determining the reasonable set of SO_2 emission control measures (Section 6.2.1), the four-factor analysis with visibility benefits evaluation (Sections 6.2.3 through 6.2.7), and the proposed emission control measures (Section 6.2.8) for the Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns.

6.2.1 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 Lime Plant SO_2 emission control measures identified the use of a fuel sulfur limit or dry scrubbing by lime production at some sources. As described in Section 2.2.4, the Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns utilize low-sulfur fuel combustion (natural gas), preheaters to reduce fuel usage, and inherent lime scrubbing during production as existing SO_2 emission control measures. Based on the air permit review (Appendix B), there are no other II&S mills that have on-site lime plants.

A coal or petroleum coke fuel sulfur limit is not appropriate in this application because the Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns fuel sources (natural gas and residual oil – AP-42 Section 11.18 gas-fired kiln SO_2 emission factor = 0.0012 lb/ton of lime produced[23]) generate less SO_2 emissions compared to solid fuel sources (coal and petroleum coke - AP-42 Section 11.17 coal-fired kiln SO_2 emission factor = 5.4 lb/ton of lime produce[23]). As such, a fuel sulfur limit is not considered in the reasonable set of SO_2 emission control measures.

There are no additional SO_2 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 Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns have no reasonable set of SO_2 emission control measures beyond what is currently installed and operated for these emission units.

6.2.2 Baseline Emission Rates

Since the four-factor analysis concluded the Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns 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.

6.2.3 Factor 1 – Cost of Compliance

Since the four-factor analysis concluded the Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns 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.

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[23] EPA; AP-42 Section 11.17 Table 11.17-6; February 1998

6.2.4 Factor 2 – Time Necessary for Compliance

Since the four-factor analysis concluded the Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns 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.

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

Since the four-factor analysis concluded the Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns 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.

6.2.6 Factor 4 – Remaining Useful Life of the Source

Since the four-factor analysis concluded the Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns 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.

6.2.7 Visibility Benefits

Since the four-factor analysis concluded the Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns 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.

6.2.8 Proposed SO_2 Emission Control Measures

The four-factor analysis concluded that additional SO_2 emission control measures at the Lime Plant No. 1 and No. 2 Preheater and Rotary Kilns beyond those described in Section 2.2.4 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.

7 80” Hot Strip Mill Walking Beam Furnaces #4-#6

The following section describes the four-factor analysis with visibility benefits evaluation for NO_X emission control measures for the 80” Hot Strip Mill WBFs #4-#6.

7.1 Four-Factor Analysis - NO_X

The following sections describe the analysis for determining the reasonable set of NO_X emission control measures (Section 7.1.1), the 2028 projected baseline NO_X emission rates (Section 7.1.2), the four-factor analysis with visibility benefits evaluation (Sections 7.1.3 through 7.1.7), and the proposed emission control measures (Section 7.1.8) for the 80” Hot Strip Mill WBFs #4-#6.

7.1.1 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 Walking Beam Furnaces NO_X emission control measures identified the use of SCR or LNB/ULNB at some sources. As described in Section 2.2.5, the units implement good combustion practices, and the #4 WBF has LNB as existing NO_X emission control measures.

The RBLC search (Appendix A) listed references to installation of SCR, LNB, ULNB, and no controls required. There is one instance of SCR for NO_X emission control, a reheat furnace at Thyssenkrupp Steel and Stainless USA, LLC (RBLC ID: AL-0230). 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 IHE. Therefore, SCR is not part of a reasonable set of NO_X emission control measures for the 80" Hot Strip Mill WBFs #4-#6.

Since 80” Hot Strip Mill WBF #4 already has ULNB installed, 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 80" Hot Strip Mill WBF #4 has no reasonable set of NO_X emission control measures beyond what is currently installed and operated for these emission units.

IHE identified LNB/ULNB to be part of the reasonable set of NO_X emission control measures for further evaluation. LNB/ULNB for the 80” Hot Strip Mill WBFs #5 and #6 is evaluated as a NO_X emission control measure in Sections 7.1.3 through 7.1.7.

7.1.2 Baseline Emission Rates

7.1.2.1 80” Hot Strip Mill WBF #4

Since the four-factor analysis concluded the 80” Hot Strip Mill WBF #4 has no reasonable set of NO_X emission control measures beyond what is currently installed and operated for this emission unit, it is not necessary to represent a projected 2028 emissions scenario.

7.1.2.2 80” Hot Strip Mill WBFs #5 and #6

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, IHE represented the projected 2028 baseline emissions based on the 2018 actual emissions, as shown in Table 7-1.

Table 7-1 Estimated 2028 Baseline NO_X Emissions for the Identified Emission Units

Unit	2028 Projected Baseline Natural Gas Throughput Assumption (MMBtu/year)	Natural Gas NO_X Emission Factor(1) (lb/MMBtu)	Estimated 2028 NO_X Emissions (tons/year)
80" HSM WBF #5	1,070	0.20	214
80" HSM WBF #6	1,033	0.23	237

(1) 80" HSM WBF #5 and #6 emission factor is based on source-specific stack testing.

7.1.3 Factor 1 – Cost of Compliance

7.1.3.1 80" Hot Strip Mill WBF #4

Since the four-factor analysis concluded the 80" Hot Strip Mill WBF #4 has no reasonable set of NO_X emission control measures beyond what is currently installed and operated for this emission unit, it is not appropriate to estimate the cost of compliance for additional NO_X emission control measures.

7.1.3.2 80" Hot Strip Mill WBFs #5 and #6

IHE completed cost estimates for LNB/ULNB installation on the 80" Hot Strip Mill WBFs #5 and #6. Cost summary spreadsheets for the NO_X emission control measures are provided in Appendix C.

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[24], 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 7-2.

[24] 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 7-2 NO_X Control Cost Summary, per Unit Basis

Annualized Capital Cost ($/yr)	Additional Emission Control Measure	Total Annualized Costs ($/yr)	Annual Emissions Reduction (tpy)	Pollution Control Cost Effectiveness ($/ton)
80" Hot Strip Mill WBF #5	ULNB	$767,000	82	$9,300
80" Hot Strip Mill WBF #6	ULNB	$767,000	110	$7,000

The cost-effectiveness values for all of the NO_X emission control measures are not justifiable because the emission control measures would not provide perceptible visibility benefits at the associated Class I areas, Section 2.1.1.2. The visibility impacts analysis completed to date indicates that IHE 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 IHE will not provide perceptible visibility benefits in these Class I areas (see Section 9.3). Further analysis through CAMx modeling that is underway is anticipated to show that IHE does not have a perceptible visibility impact on these Class I areas. Therefore, the costs for the retrofit options are not reasonable.

Therefore, the costs for the additional NO_X emission control measure options are not reasonable.

Sections 7.1.4 through 7.1.7 provide a summary of the remaining factors evaluated for the NO_X emission control measures, understanding that these projects represent substantial costs that are not justified on a cost per ton or absolute cost basis.

7.1.4 Factor 2 – Time Necessary for Compliance

7.1.4.1 80" Hot Strip Mill WBF #4

Since the four-factor analysis concluded the 80" Hot Strip Mill WBF #4 has no reasonable set of NO_X emission control measures beyond what is currently installed and operated for this emission unit, it is not appropriate to describe the time that is necessary to achieve compliance for additional NO_X emission control measures.

7.1.4.2 80" Hot Strip Mill WBFs #5 and #6

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 IHE'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 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. 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.

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

7.1.5.1 80” Hot Strip Mill WBF #4

Since the four-factor analysis concluded the 80” Hot Strip Mill WBF #4 has no reasonable set no reasonable set of NO_X emission control measures beyond what is currently installed and operated for this emission unit, it is not appropriate to describe the energy and non-air quality environmental impacts for additional NO_X emission control measures.

7.1.5.2 80” Hot Strip Mill WBFs #5 and #6

LNB/ULNB installation on the 80" Hot Strip Mill WBFs #5 and #6 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/ULNB are negligible for this analysis.

7.1.6 Factor 4 – Remaining Useful Life of the Source

7.1.6.1 80” Hot Strip Mill WBF #4

Since the four-factor analysis concluded the 80” Hot Strip Mill WBF #4 has no reasonable set of NO_X emission control measures beyond what is currently installed and operated for this emission unit, it is not appropriate to describe the remaining useful life of the source.

7.1.6.2 80” Hot Strip Mill WBFs #5 and #6

Because IHE 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.

7.1.7 Visibility Benefits

7.1.7.1 80” Hot Strip Mill WBF #4

Since the four-factor analysis concluded the 80” Hot Strip Mill WBF #4 has no reasonable set of NO_X emission control measures beyond what is currently installed and operated for this emission unit, it is not appropriate to describe the potential visibility benefits for additional NO_X emission control measures.

7.1.7.2 80” Hot Strip Mill WBFs #5 and #6

Independent of the four-factor analysis, LNB/ULNB installation on the 80" Hot Strip Mill WBFs #5 and #6 is not appropriate and is 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 (499 km), Seney (513 km) and Isle Royale (699 km)), or trending towards and expected to attain without additional emission reductions the 2028 URP (Mingo (561 km)) (see Section 9.1),
2. The visibility impacts analysis completed to date indicates that IHE is not a contributor to perceptible visibility impairment to the Class I areas on the most impaired days (see Section 9.3) and is not expected to have a perceptible contribution to visibility impacts based on CAMx modeling that is underway, and
3. LNB/ULNB installation on the 80" Hot Strip Mill WBFs #5 and #6 does not justify the associated costs, as described in Section 7.1.3, because the emission control measures are neither necessary to, nor expected to provide perceptible visibility benefits.

7.1.8 Proposed NO_X Emission Control Measures

Based on the four-factor analysis with visibility benefits evaluation, installation of additional NO_X emission control measures at the 80" Hot Strip Mill WBFs #4-#6 beyond those described in Section 2.2.5 are not required to make reasonable progress. As such, this analysis proposes to maintain the existing NO_X emission control measures.

8 Sinter Plant Windbox

The following sections describe the four-factor analyses with visibility benefits evaluations for NO_X and SO_2 emission control measures for the Sinter Plant Windbox.

8.1 Four-Factor Analysis - NO_X

The following sections describe the analysis for determining the reasonable set of NO_X emission control measures (Section 8.1.1), the four-factor analysis with visibility benefits evaluation (Sections 8.1.3 through 8.1.7), and the proposed emission control measures (Section 8.1.8) for the Sinter Plant Windbox.

8.1.1 NO_X Emission Control Measures

As described in Section 2.2.6, the Sinter Plant Windbox utilizes good combustion practices as a NO_X emission control measure. The RBLC search (summarized in Appendix A) and search of air permits for II&S mills and similar sources (Appendix B) for Sinter Plants did not identify any NO_X emission control measures.

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 II&S mills (Appendix B). As such, the Sinter Plant Windbox has no reasonable set of NO_X emission control measures beyond what is currently installed and operated for this emission unit.

8.1.2 Baseline Emission Rates

Since the four-factor analysis concluded the Sinter Plant Windbox has no reasonable set of NO_X emission control measures beyond what is currently installed and operated for this emission unit, it is not necessary to represent a projected 2028 emissions scenario.

8.1.3 Factor 1 – Cost of Compliance

Since the four-factor analysis concluded the Sinter Plant Windbox has no reasonable set of NO_X emission control measures beyond what is currently installed and operated for this emission unit, it is not appropriate to estimate the cost of compliance for additional NO_X emission control measures.

8.1.4 Factor 2 – Time Necessary for Compliance

Since the four-factor analysis concluded the Sinter Plant Windbox has no reasonable set of NO_X emission control measures beyond what is currently installed and operated for this emission unit, it is not appropriate to describe the time that is necessary to achieve compliance for additional NO_X emission control measures.

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

Since the four-factor analysis concluded the Sinter Plant Windbox has no reasonable set of NO_X emission control measures beyond what is currently installed and operated for this emission unit, it is not appropriate to describe the energy and non-air quality environmental impacts for additional NO_X emission control measures.

8.1.6 Factor 4 – Remaining Useful Life of the Source

Since the four-factor analysis concluded the Sinter Plant Windbox has no reasonable set of NO_X emission control measures beyond what is currently installed and operated for this emission unit, it is not appropriate to describe the remaining useful life of the source.

8.1.7 Visibility Benefits

Since the four-factor analysis concluded the Sinter Plant Windbox has no reasonable set of NO_X emission control measures beyond what is currently installed and operated for this emission unit, it is not appropriate to describe the potential visibility benefits for additional NO_X emission control measures.

8.1.8 Proposed NO_X Emission Control Measures

The four-factor analysis concluded that additional NO_X emission control measures at the Sinter Plant Windbox beyond those described in Section 2.2.6 are not required to make reasonable progress. As such, this analysis proposes to maintain the existing NO_X emission control measures.

8.2 Four-Factor Analysis – SO_2

The following sections describe the analysis for determining the reasonable set of SO_2 emission control measures (Section 8.2.1), the 2028 projected baseline SO_2 emission rates (Section 8.2.2), the four-factor analysis with visibility benefits evaluation (Sections 8.2.3 through 8.2.7), and the proposed emission control measures (Section 8.2.8) for the Sinter Plant Windbox.

8.2.1 SO_2 Emission Control Measures

As described in Section 2.2.6, the Sinter Plant Windbox utilizes routine material sampling and sinter feed management as an SO_2 emission control measure. The RBLC search (summarized in Appendix A) and search of air permits for II&S mills and similar sources (Appendix B) for Sinter Plant SO_2 emission control measures identified the use of wet scrubbing, spray dryer absorber installation, and/or dry sorbent injection.

The Sinter Plant Windbox is already controlled for PM, a visibility impairing pollutant, using baghouses. A wet scrubber system may result in unacceptable increases to PM because the existing baghouse (dry controls) would need to be removed for compatibility issues (e.g., wetting the bag) associated with a wet scrubber system. Furthermore, the SO_2 that is captured by the scrubber would need to be neutralized and treated as wastewater. Since the associated issues are not present and the SO_2 emission control performance is generally comparable with spray dryer absorbers or dry sorbent injection (dry controls), wet scrubbing was excluded from the reasonable set of SO_2 emission control measures.

Spray dryer absorber installation and dry sorbent injection for the Sinter Plant Windbox are evaluated as SO_2 emission control measures in Sections 8.2.3 through 8.2.7.

8.2.2 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, IHE represented the projected 2028 baseline emissions based on the 2018 actual emissions, as shown in Table 8-1.

Table 8-1 Estimated 2028 Baseline SO_2 Emissions for the Identified Emission Units

Unit	2028 Projected Baseline Sinter Throughput Assumption (tons/year)	Sinter SO_2 Emission Factor[(1)] (lb/ton)	Estimated 2028 SO_2 Emissions (tons/year)
Sinter Plant Windbox	1,075,426	0.69	371

(1) Emission factor is based on the source-specific stack testing.

8.2.3 Factor 1 – Cost of Compliance

IHE completed cost estimates for spray dryer installation and dry sorbent injection on the Sinter Plant Windbox. Cost summary spreadsheets for the SO_2 emission control measures are provided in Appendix C.

The cost-effectiveness analysis compares the annualized cost of the 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 installation of dry sorbent injection or a spray dryer absorber would require significant modifications to the current pollution control train. The existing baghouse is unable to accommodate additional particulate loading. Therefore, a new baghouse would be required for both emission control measures, capable of capturing process and sorbent dust. In addition, new controls cannot be installed while the plant is operating. Plot space surrounding the Sinter Plant is very limited and it is not feasible to construct a new baghouse without blocking vehicle and truck traffic required to operate the process. Therefore, the Sinter Plant would need to be shut down for a minimum of 4-6 months to demolish the current controls and install dry sorbent injection or a spray dryer absorber. This would result in a large lost production cost to the facility, which is not accounted for in the control costs, but is not economically feasible for IHE.

To account for the limited space around existing equipment, a 50 percent markup of the total capital investment (i.e., a 1.5 retrofit factor) was included in the costs to account for the installation. Retrofit installations have increased handling and erection difficulty for many reasons. Access for transportation, laydown space, etc. for new equipment is significantly impeded or restricted. As noted above, the spaces surrounding the Sinter Plant are congested, or the areas surrounding the Sinter Plant support frequent vehicle traffic or crane access for maintenance and cannot be used for material staging. Additionally, the emission control measures evaluated in this section are complex and increase the associated installation costs (e.g., ancillary equipment requirements, piping, structural, electrical, demolition, etc.). Finally, the EPA Control Cost Manual[26] notes that retrofit installations are subjective because the plant designers may not have had the foresight to include additional floor space and room between components for new equipment. Retrofits impose additional costs to "shoehorn" equipment in existing plant space, which is true for the Sinter Plant.

The resulting cost-effectiveness calculations are summarized in Table 8-2.

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[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

[26] US EPA, "EPA Air Pollution Control Cost Manual, Sixth Edition," Section 1, Chapter 2.6.4.2 Retrofit Cost Considerations. 2017. https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

Table 8-2 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)
Sinter Plant Windbox	Spray Dryer Absorber	$9,651,000	334	$28,900
Sinter Plant Windbox	Dry Sorbent Injection	$9,924,000	260	$38,200

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 IHE 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 IHE will not provide perceptible visibility benefits in these Class I areas (see Section 9.3). Further analysis through CAMx modeling that is underway is anticipated to show that IHE 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 8.2.4 through 8.2.7 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.

8.2.4 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 IHE'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.

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

The spray dryer absorber and dry sorbent injection would increase energy usage due to the higher pressure drop across absorber vessel (spray dryer absorber only) and the downstream baghouse, material preparation such as grinding reagents, additional material handling equipment such as pumps and blowers, and steam requirements. Power consumption is also affected by the reagent utilization, which also affects the associated control efficiency. As a minimum, this would require increased electrical usage by the plant with associated increase indirect (secondary) emissions from nearby power stations. The new process gas duct burners will consume additional fuel to evaporate spray dryer moisture. The cost of energy required to operate the spray dryer absorber and dry sorbent injection have been included in the cost analysis found in Appendix C.

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

8.2.6 Factor 4 – Remaining Useful Life of the Source

Because IHE 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.

8.2.7 Visibility Benefits

Independent of the four-factor analysis, installation of a spray dryer absorber and dry sorbent injection on the Sinter Plant Windbox 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 (499 km), Seney (513 km) and Isle Royale (699 km)), or trending towards and expected to attain without additional emission reductions (Mingo (561 km)), the 2028 URP (see Section 9.1),
2. The visibility impacts analysis completed to date indicates that IHE is not a contributor to perceptible visibility impairment to the Class I areas on the most impaired days (see Section 9.3) 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 and dry sorbent injection on the Sinter Plant Windbox does not justify the associated costs, as described in Section 8.2.3, because the emission control measures are neither necessary to, nor expected to provide perceptible visibility benefits.

8.2.8 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 Sinter Plant Windbox beyond those described in Section 2.2.6 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.

9 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 9-1 shows a map of the IHE 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 (499 km)
- Seney National Wildlife Refuge – Michigan (513 km)
- Mingo National Wildlife Refuge – Missouri (561 km)
- Isle Royale National Park – Michigan (699 km)

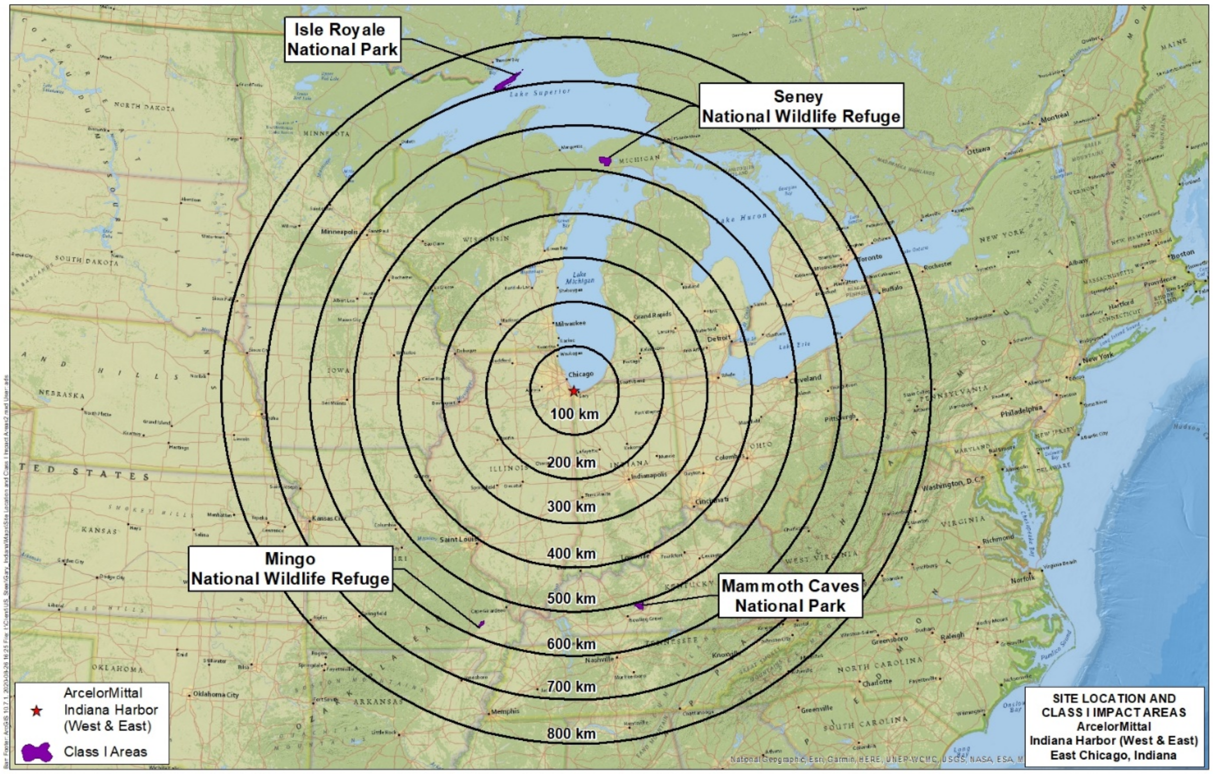

Figure 9-1 Location of Class I Areas in Relation to the Indiana Harbor East Facility

Section 9.1 provides an analysis of current visibility conditions at the four Class I areas presented in Figure 9-1 while Section 9.2 evaluates the emission trends that are impacting visibility in these Class I areas. Section 9.3 provides a review of previously completed visibility modeling and screening analysis which illustrate that emission reductions at IHE are unlikely to improve visibility on the most impaired days at these Class I areas.

9.1 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"[27] 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.[28] 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 9-1.

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 9-2 through Figure 9-5 show the rolling 5-year average visibility impairment based on IMPROVE monitoring data compared with the URP glidepath at Mammoth Cave (499 km), Mingo (561 km), Isle Royale (699 km), and Seney (513 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 (499 km) (Figure 9-2), Isle Royale (699 km) (Figure 9-4), and Seney (513 km) (Figure 9-5) are already below the 2028 glidepath and have continued trending downward since. The visibility at Mingo (561 km) (Figure 9-3) 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.

[27] 40 CFR 51.308(f)(1)
[28] 40 CFR 51.308(f)(3)

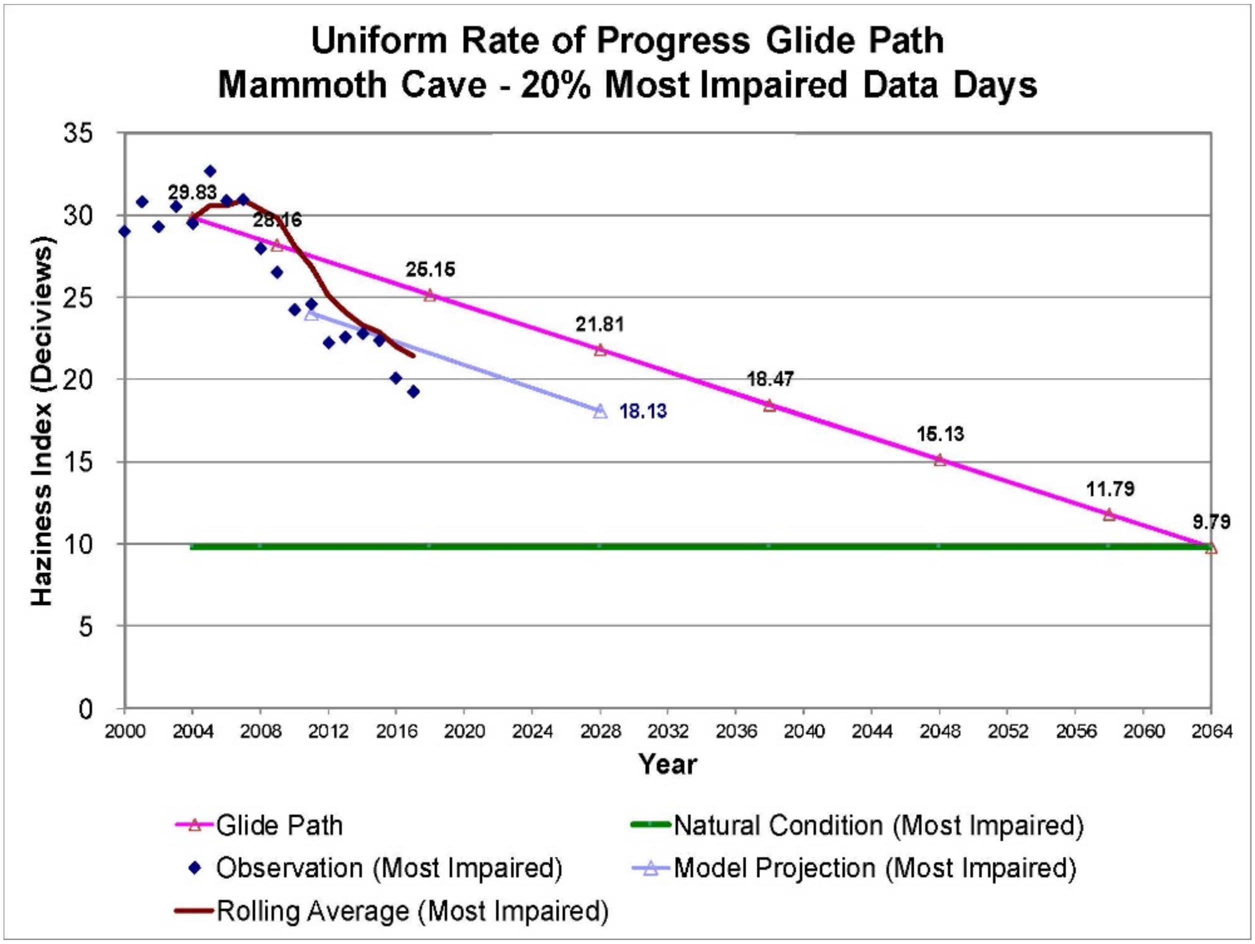

Figure 9-2 Visibility Trend versus URP – Mammoth Cave National Park (499 km)[29]

[29] 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)

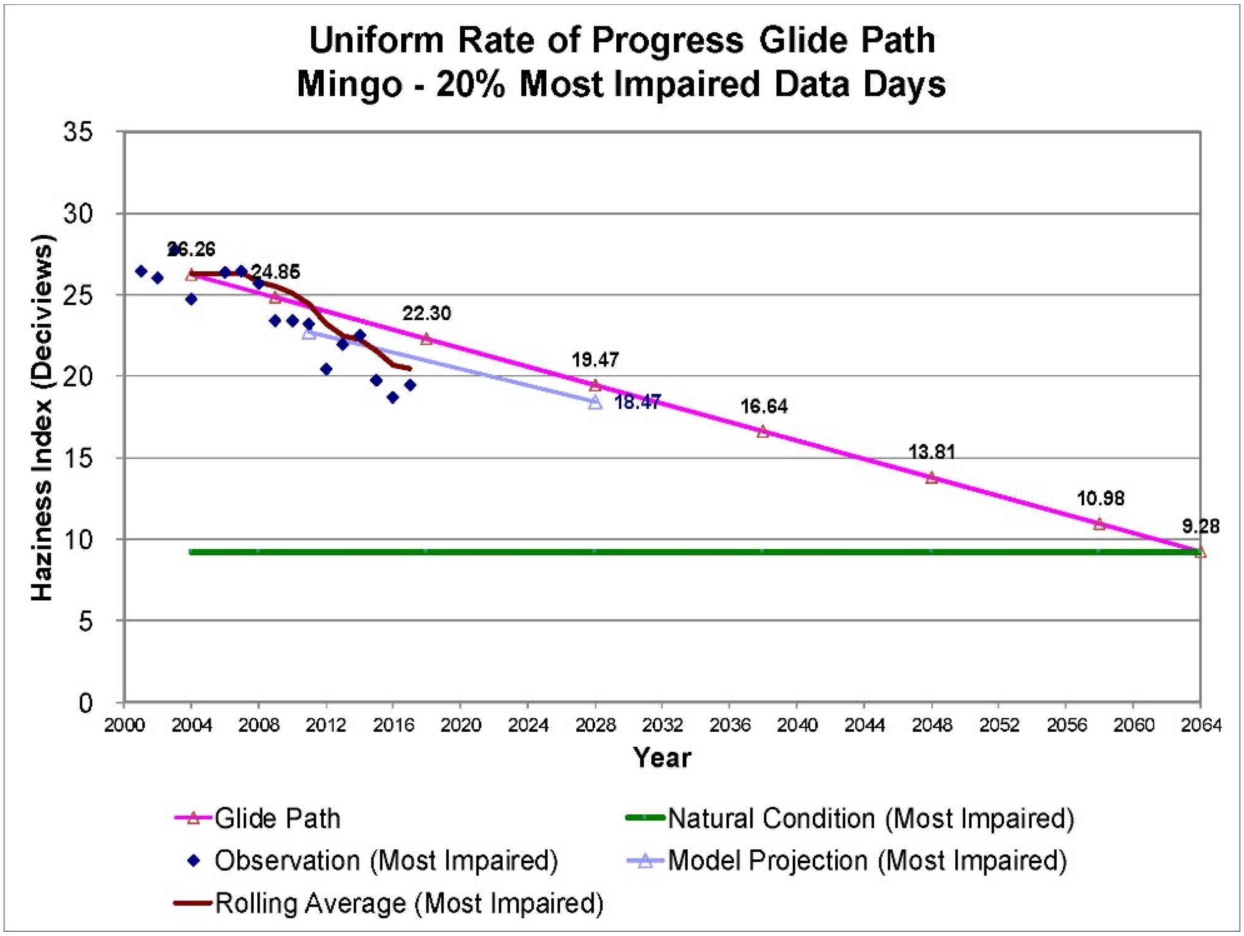

Figure 9-3 Visibility Trend versus URP – Mingo National Wildlife Refuge (561 km)[30]

[30] 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)

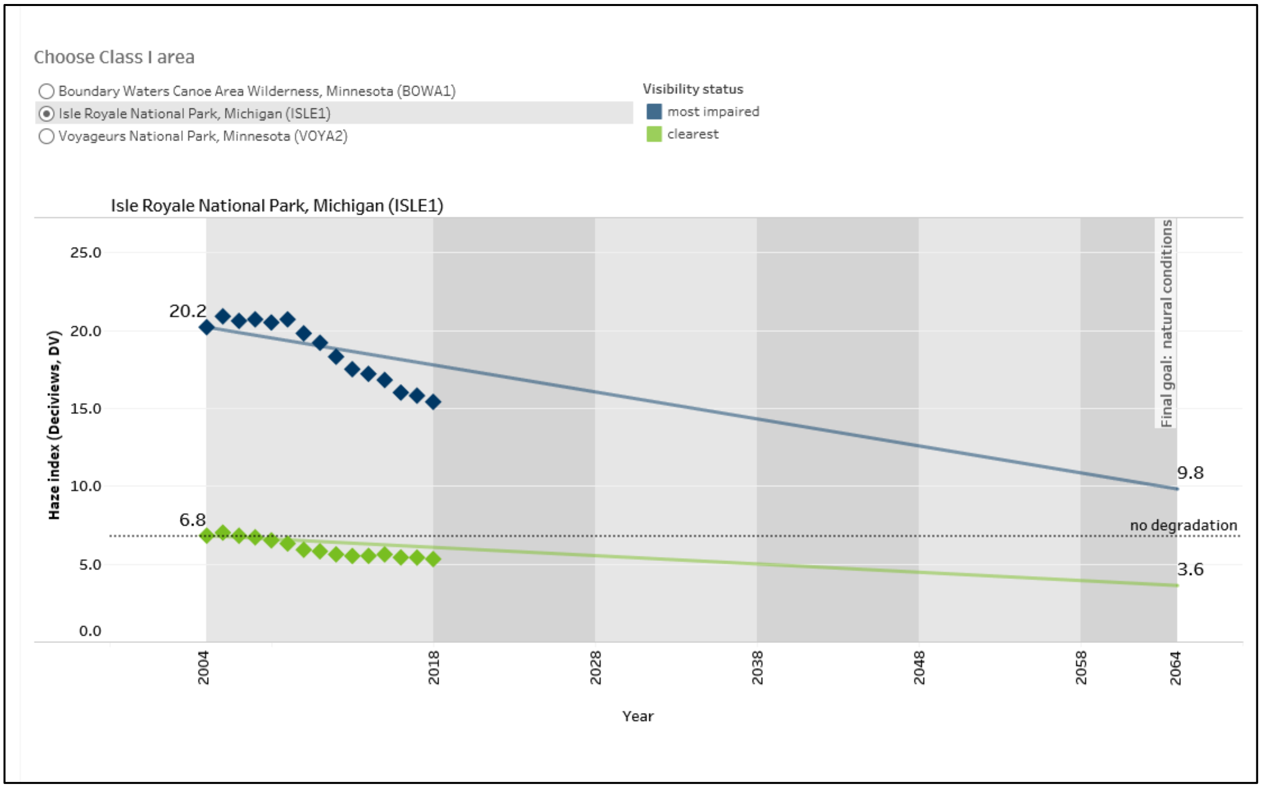

Figure 9-4 Visibility Trend versus URP – Isle Royale National Park (699 km)[31]

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

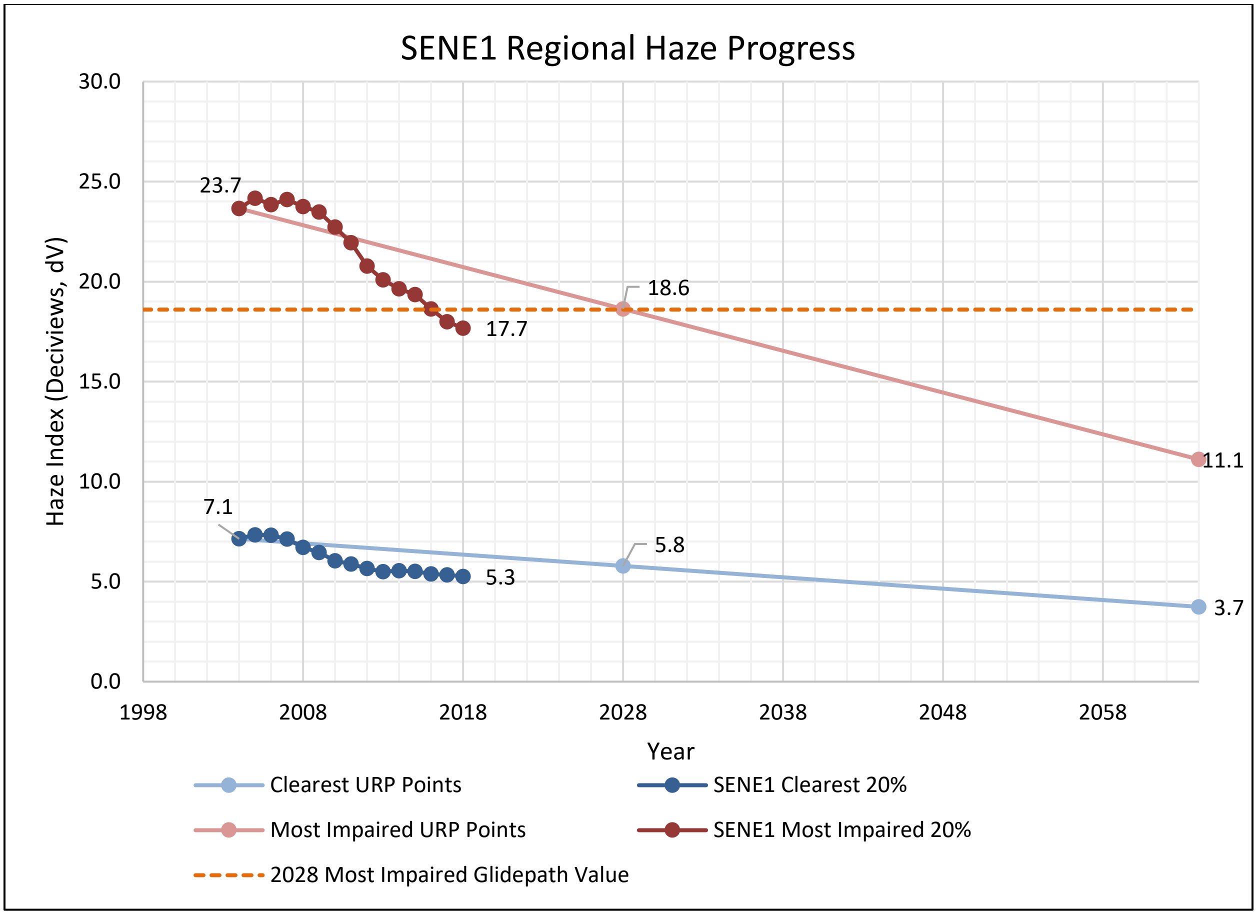

Figure 9-5 Visibility Trend versus URP – Seney National Wildlife Refuge (513 km)[32]

9.2 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 9-6 and Figure 9-7, respectively.

[32] IMPROVE monitoring network (http://vista.cira.colostate.edu/Improve/)

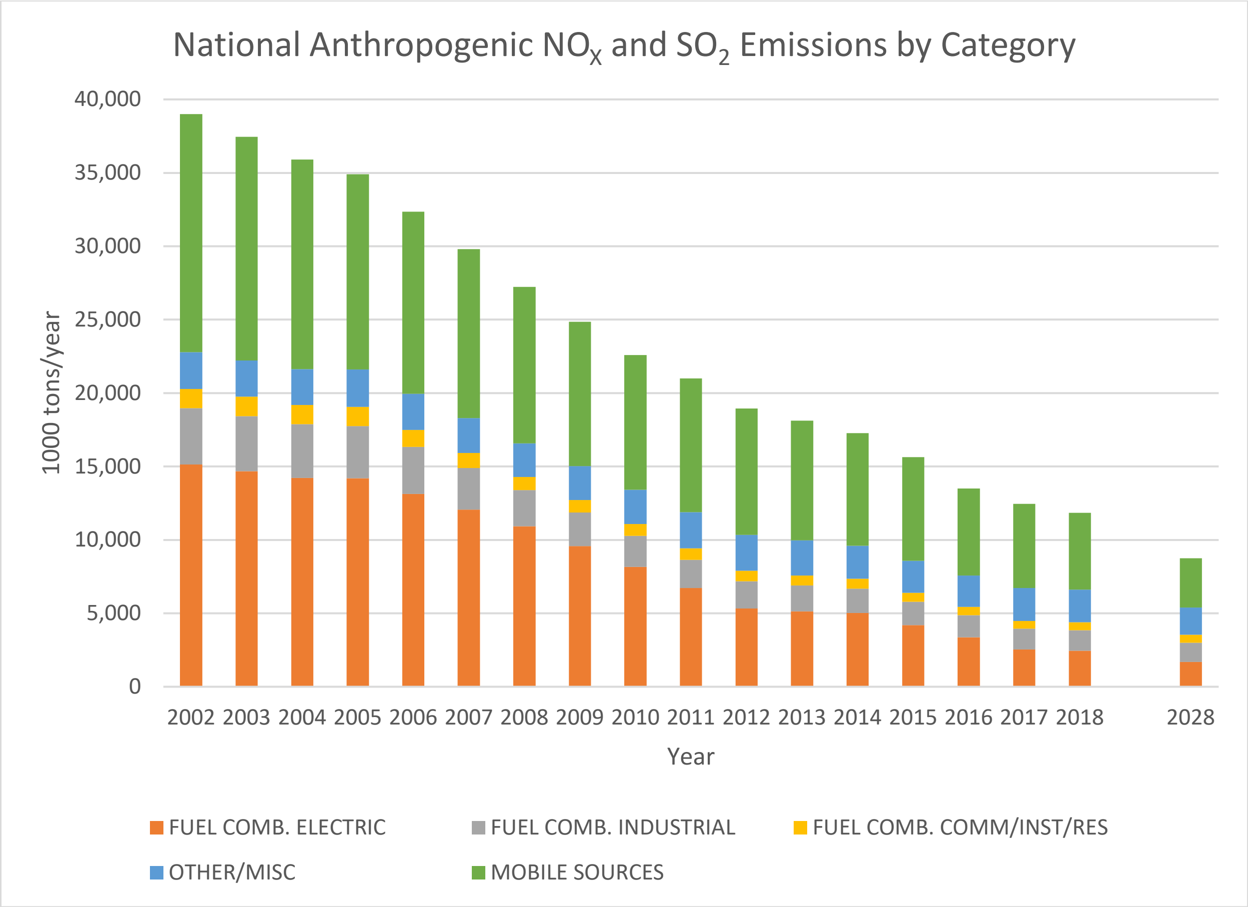

Figure 9-6 National NO_X and SO_2 Emission Trends

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[33] and the 2028 data was obtained from page 18 of EPA's regional haze modeling summary which includes the summary of modeled emissions[34].

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[33] EPA Air Pollutant Emission Trends Data, National Annual Emission Trend

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

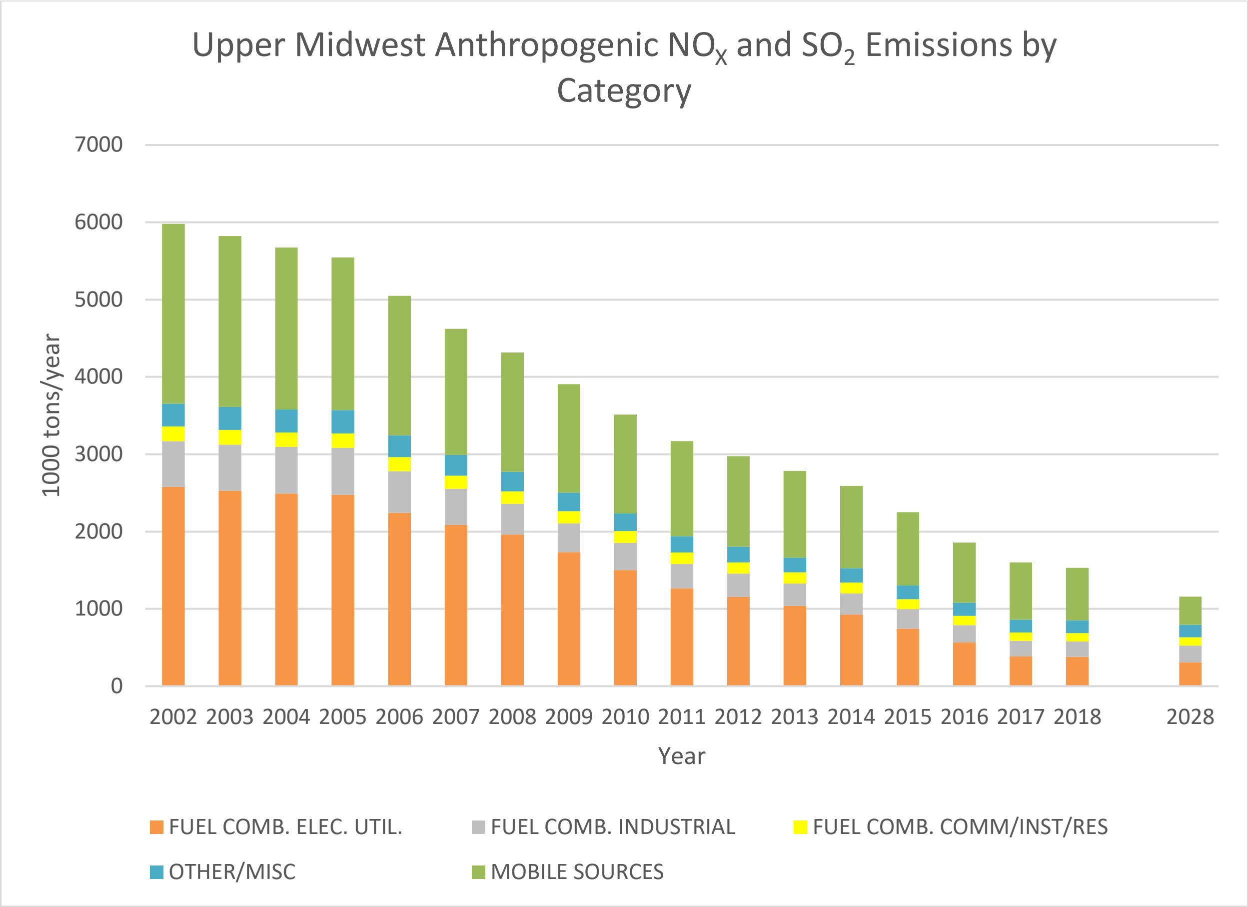

Figure 9-7 Upper Midwest NO_X and SO_2 Emission Trends

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 IHE. The 2002-2018 emissions contained in the included state summaries was obtained from the EPA's state annual emission trends[35] and the 2028 data was obtained from the EPA's 2016v1 modeling platform that also includes 2028 modeling data[36].

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 9-1 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 9-1 have

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[35] EPA Air Pollutant Emission Trends Data, State Annual Emission Trend

[36] 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 9-1 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.[37] 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 IHE are not required to make reasonable progress in reducing NO_X and SO_2 emissions.

9.3 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

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

measure is necessary to make reasonable progress."[38] This guidance also says that "the decision-making 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."[39] Although the cost of compliance evaluations as presented in Sections 6.1.3, 7.1.3, and 8.2.3 demonstrate that additional control measures are not cost effective, Barr completed an evaluation to determine if an emissions reduction at the Indiana Harbor East facility would result in visibility improvements at the nearest Class I areas.

9.3.1 BART Modeling

As part of the previous regional haze planning evaluation, and to demonstrate that the Burns Harbor facility cannot reasonably be anticipated to cause or contribute to visibility impairment in a Class I area, ArcelorMittal completed site-specific visibility modeling of Burns Harbor's 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 Burns Harbor 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).[40] 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).

Although the 2008 site specific BART modeling report was conducted for Burns Harbor, the IHE facility is approximately 16 miles west of Burns Harbor and, therefore is located at similar distances and locations relative to the closest Class I areas. Furthermore, the results of a long-range transport model are more dependent on the total emission rate as opposed to the individual stack parameters (velocity and temperature) and facility downwash characteristics. Thus, the modeling analysis conducted for Burns Harbor was used as an indicator of visibility impact from this facility because of the relative locations of the two facilities compared to the modeled Class I areas, and because the modeled emissions from Burns Harbor are much higher than the emissions from IHE.

The 2008 site-specific visibility modeling for Burns Harbor 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 (499 km), Seney (513 km), Mingo (561 km), and Isle Royale (699 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

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[38] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," 08/20/2019, Page 37.
[39] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," 08/20/2019, Page 37.
[40] 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)

CALPUFF is known to over predict impacts beyond 300 km.[41] 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.[42] However, with the 2017 revisions to the *Guideline on Air Quality Models*[43], 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 Group (FLAG).[44] 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 Burns Harbor 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[45] amount to visibility impairment and was exempt from BART.

The current emissions of SO_2 and NO_X from IHE are significantly less than the conservatively high emission rates which were used in the Burns Harbor 2008 CALPUFF modeling. Therefore, the current visibility impacts from IHE 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. IHE 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 IHE, even on the most impaired days.

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[41] 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)

[42] CALPUFF Regulatory Status, http://www.src.com/calpuff/regstat.htm

[43] Appendix W to 40 CFR Part 51

[44] 2010 FLAG Phase I Report Revised, https://irma.nps.gov/DataStore/DownloadFile/420352, October 2010, Page 23.

[45] 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)

9.3.2 Mammoth Cave and Mingo Trajectory Analysis

Consistent with the EPA Guidance on Regional Haze SIPs for the Second Implementation Plan, the VISTAS[46] and CENRAP[47] 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.[48] This update provides additional information related to IHE and the lack of impact on Mammoth Cave (499 km). As described in the project update, VISTAS performed a 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 (499 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 (499 km), there were five sources in Indiana that were flagged for further analyses using photochemical modeling (i.e., flagged for the PSAT modeling analysis). IHE 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 IHE as it was not included as a specifically "flagged" source 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[49]. The level of detail provided by CENRAP allows for a specific evaluation of the impacts from IHE when compared to the state-selected threshold of 1% visibility culpability at Mingo in southeastern Missouri (561 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, IHE did not exceed the 1% threshold as shown in Table 9-2.

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[46] Visibility Improvement State and Tribal Association of the Southeast (VISTAS), https://www.metro4-sesarm.org/.
[47] Central Regional Air Planning Association (CENRAP), https://www.cenrap.org/.
[48] 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)
[49] Central States Air Resources Agencies (CenSARA), "Determining Areas of Influence – CenSARA Round Two Regional Haze", November 2018, https://censara.org/ftpfiles/Ramboll/.

Table 9-2 Sulfate and Nitrate Culpability at Mingo National Wildlife Refuge

Facility	Sulfate Culpability	Nitrate Culpability	Sulfate + Nitrate Culpability
Indiana Harbor (East and West, combined)	0.07%	0.16%	0.09%

The CENRAP findings indicate that no additional analyses are necessary for either of the ArcelorMittal Indiana Harbor facilities as the combined impact from the facilities was less than the 1% threshold for sulfate plus nitrate culpability.

9.3.3 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 (513 km) and Isle Royale (699 km) to determine if emissions from IHE could be contributing to visibility impacts in these Class I areas on the most impaired days. These analyses could also be used to determine if emission reductions at IHE 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[50] was used to calculate the 20% most impaired days for 2017 and 2018. The NOAA Hysplit model[51] 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.[52]

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 9–8 and Figure 9–9, only one of the most impaired trajectories crosses near IHE for Seney (513 km) and none of the most impaired trajectories passes near IHE for Isle Royale (699 km). In addition, these figures illustrate

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[50] 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

[51] 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

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

that the majority of the most impaired trajectories are not traveling from the general direction of IHE or the greater Chicago area. Furthermore, most of the 48-hour reverse trajectories end before reaching IHE and the greater Chicago area, indicating that Seney (513 km) and Isle Royale (699 km) are at a distance far enough away from the facility that a perceptible visibility impairment from the IHE facility is extremely unlikely. These figures also demonstrate that sources from other regions, and not IHE, are contributing to the visibility on the most impaired days at the monitors.

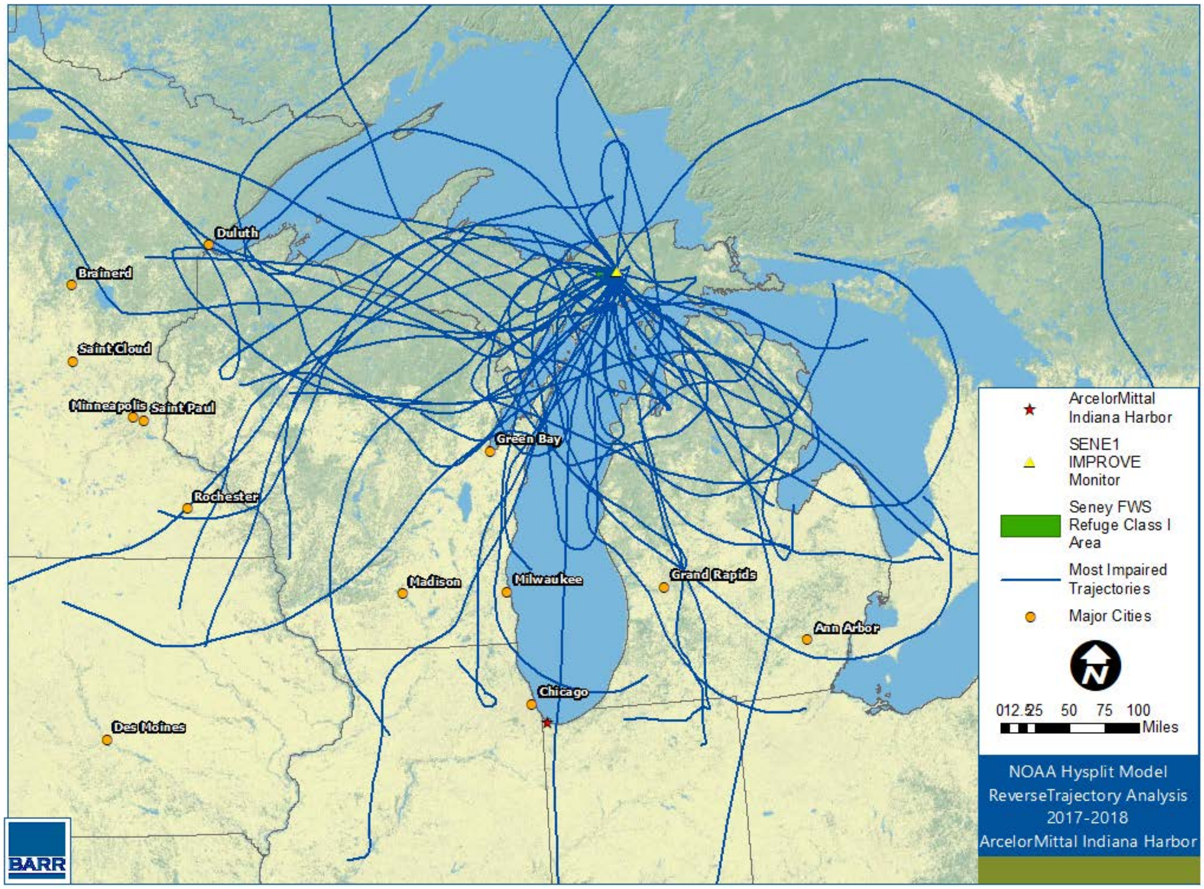
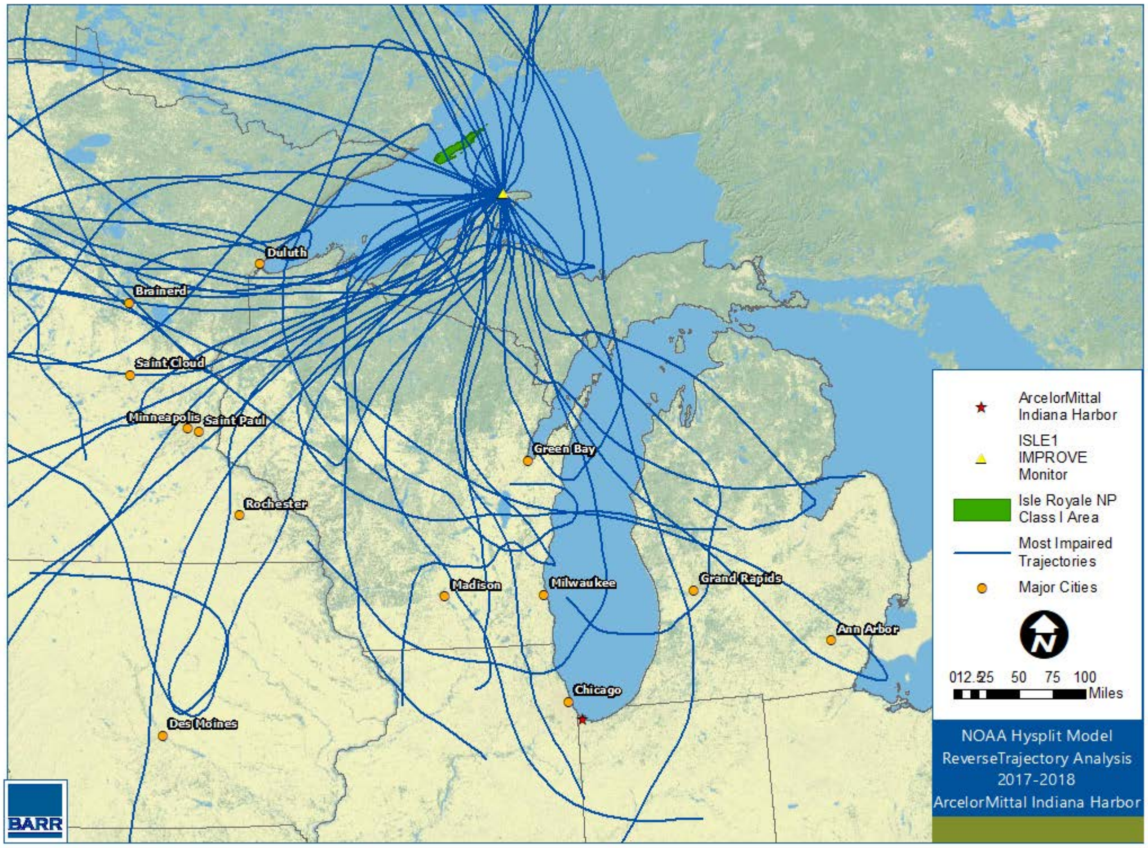


Figure 9–8 Seney National Wildlife Refuge: Most Impaired Trajectories for 2017-2018 from Reverse Trajectory Analysis



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

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

9.3.4 Visibility Impacts Conclusion

Based on the previous conservative BART modeling, the screening analyses conducted by VISTAS (Mammoth Cave (499 km)) and CENRAP (Mingo (561 km)), the culpability screening analyses for Seney (513 km) and Isle Royale (699 km), and the back trajectory analyses for Seney (513 km) and Isle Royale (699 km), Barr concludes that emissions from IHE 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.

10 Conclusion

The four-factor analyses with visibility benefits evaluations for the No. 4 Basic Oxygen Furnace (NO_X, Section 3.1), the No. 5 Boiler House Boilers 501-504 (NO_X, Section 4.1; SO_2, Section 4.2), the No. 7 Blast Furnace Stoves, Casthouse, and Flares (NO_X, Section 5.1; SO_2, Section 5.2), the Lime Plant Nos. 1 and 2 Kilns and Preheater (NO_X, Section 6.1; SO_2, Section 6.2), and the 80" HSM #4 WBF (NO_X, Section 7.1.1) 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 and SO_2 emission control measures is not technically feasible for these emission units.
- Therefore, the existing NO_X and SO_2 emission performance for these emission units are sufficient for the IDEM's regional haze reasonable progress goal.

As described in Section 7, the 80" HSM #5 and #6 WBF 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 ULNB for #5 and #6 WBFs.
- The associated NO_X cost-effectiveness values ($ per ton of emissions reduction) of the reasonable set of additional NO_X emission control measures are not reasonable.
- Independent of the four-factor analysis, additional NO_X emission reductions are not appropriate and are unnecessary for the #5 and #6 WBFs 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 (499 km), Seney (513 km), and Isle Royale (699 km)), or trending towards and expected to attain without additional emission reductions (Mingo (561 km)), the 2028 URP (see Section 9.1), and
    - The visibility impacts analysis completed to date indicates that IHE 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 IHE 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 9.3). Further analysis through CAMx modeling that is underway is anticipated to confirm that IHE does not have a perceptible visibility impact on these Class I areas. IHE reserves the right to amend and/or supplement this report and visibility analysis once CAMx modeling has been completed.
- Therefore, the 80" Hot Strip Mill #5 and #6 WBFs existing NO_X emission performances are sufficient for the IDEM's regional haze reasonable progress goal.

As described in Section 8, the Sinter Plant Windbox NO_X and SO_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 Sinter Plant Windbox. There is no available set of additional NO_X emission control measures for this emission unit.
- The reasonable set of SO_2 emission control measures beyond what is currently installed and operated for this emission unit consists of spray dryer absorbers and dry sorbent injection.
- 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 80" Hot Strip Mill #4, #5, and #6 WBFs conclusion above, additional NO_X and SO_2 emission reductions are not appropriate and are unnecessary for the Sinter Plant Windbox, independent of the four-factor analysis, because IHE 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 9).
- Therefore, the Sinter Plant Windbox 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

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-0292	WHEELING PITTSBURGH STEEL CORPORATION	WHEELING PITTSBURGH STEEL CORPORATION	OH	06-07507	331110	1/6/2005	STEEL MANUFACTURING	BASIC OXYGEN FURNACES (2 VESSELS), FUGITIVE		375	t/h	Nitrogen Oxides (NOx)		7.5	LB/H		BACT-PSD	16.4	T/YR		0		
OH-0292	WHEELING PITTSBURGH STEEL CORPORATION	WHEELING PITTSBURGH STEEL CORPORATION	OH	06-07507	331110	1/6/2005	STEEL MANUFACTURING	BASIC OXYGEN FURNACE (2 VESSELS) SCRUBBER		375	t/h	Nitrogen Oxides (NOx)		30	LB/H		BACT-PSD	56.6	T/YR		0		

ArcelorMittal Indiana Harbor East
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)

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-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 Indiana Harbor East
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)

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
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

ArcelorMittal Indiana Harbor East
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emissions Control
Appendix A: EPA RACT BACT LAER Clearinghouse Data
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)

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	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	

ArcelorMittal Indiana Harbor East
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emissions Control
Appendix A: EPA RACT BACT LAER Clearinghouse Data
Blast Furnace

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 A: EPA RACT BACT LAER Clearinghouse Data

Flares in the Ferrous Metals Industry

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-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		

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
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		

ArcelorMittal Indiana Harbor East
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emissions Control
Appendix A: EPA RACT BACT LAER Clearinghouse Data
Rotary Lime Kiln

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
AR-0082	ARKANSAS LIME COMPANY	ARKANSAS LIME COMPANY	AR	0045-AOP-R3	212312	8/30/2005	LIMESTONE MINING AND LIME PRODUCTION	LIME KILN, SN-30Q	COAL/COKE AND NATURAL GAS	45254	T/YR	Nitrogen Oxides (NOx)		3.5	LB/T	LB/TON OF LIME, 30 DAY ROLLING AVERAGE	BACT-PSD	0			0		
OH-0321	MARTIN MARIETTA MATERIALS	MARTIN MARIETTA MAGNESIA SPECIALTIES, LLC	OH	03-17089	327410	11/13/2008	LIME MANUFACTURING PLANT. DOLOMITIC LIME IS PRODUCED FROM LIMESTONE CONTAINING BETWEEN 30 TO 45% MAGNESIUM CARBONATE.	ROTARY LIME KILN	COAL, COKE, NATURAL GAS	18000	LB/H	Nitrogen Oxides (NOx)		673.43	T/YR	PER ROLLING 12-MONTH PERIOD	BACT-PSD	0.14	LB/MMBTU	FROM NATURAL GAS COMBUSTION	4.1	LB/T	PER TON OF LIME
WI-0233	CLM - SUPERIOR	CUTLER-MAGNER COMPANY	WI	05-DCF-412	327410	8/16/2006	LIME MANUFACTURING	LIME KILN (P50)	COAL / PET COKE	650	T/D	Nitrogen Oxides (NOx)	USE OF A PREHEATER TYPE ROTARY KILN AND GOOD COMBUSTION PRACTICES / OPTIMIZATION WHICH MINIMIZE NITROGEN OXIDE EMISSIONS (WHILE MAINTAINING	98.8	LB/H	3 HOUR AVG.	BACT-PSD	0.7	LB/MMBTU	MONTHLY AVERAGE	1.83	LB/T	24 HOUR AVG.
*WI-0291	GRAYMONT WESTERN LIME-EDEN	GRAYMONT WESTERN LIME-EDEN	WI	18-RAB-010	327410	1/28/2019	Lime Manufacturing	P33 Lime Kiln #1	Natural Gas/Coal	0		Nitrogen Oxides (NOx)	Good Combustion Practices and the Use of Low-NOx Burners	43.8	LB/HR	30 DAY AVERAGE	BACT-PSD	1.5	LB/TON STONE FEED	365 DAY AVERAGE	0		
*WI-0291	GRAYMONT WESTERN LIME-EDEN	GRAYMONT WESTERN LIME-EDEN	WI	18-RAB-010	327410	1/28/2019	Lime Manufacturing	P34 Lime Kiln #2	Natural Gas/Coal	0		Nitrogen Oxides (NOx)	Good Combustion Practices and the Use of Low-NOx Burners	68.8	LB/HR	30 DAY AVERAGE	BACT-PSD	1.5	LB/TON STONE FEED	365 DAY AVERAGE	0		

ArcelorMittal Indiana Harbor East
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emissions Control
Appendix A: EPA RACT BACT LAER Clearinghouse Data
Rotary Lime Kiln

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
AR-0082	ARKANSAS LIME COMPANY	ARKANSAS LIME COMPANY	AR	0045-AOP-R3	212312	8/30/2005	LIMESTONE MINING AND LIME PRODUCTION	LIME KILN, SN-30Q	COAL/COKE AND NATURAL GAS	45254	T/YR	Sulfur Dioxide (SO2)	DRY SCRUBBING BY LIME PRODUCTION, FUEL SULFUR LIMITS: 4% S BY WT ON DRY BASIS, OR 3% S BY WT IN FUEL ON 30-DAY ROLLING AVERAGE.	0		SEE NOTE	BACT-PSD	0			0		
OH-0321	MARTIN MARIETTA MATERIALS	MARTIN MARIETTA MAGNESIA SPECIALTIES, LLC	OH	03-17089	327410	11/13/2008	LIME MANUFACTURING PLANT. DOLOMITIC LIME IS PRODUCED FROM LIMESTONE CONTAINING BETWEEN 30 TO 45% MAGNESIUM CARBONATE.	ROTARY LIME KILN	COAL, COKE, NATURAL GAS	18000	LB/H	Sulfur Dioxide (SO2)		279.23	T/YR	PER ROLLING 12-MONTH PERIOD	BACT-PSD	63.79	LB/H	FROM COAL OR PETROLEUM COKE FUELS	1.7	LB/T	PER TON OF LIME
TX-0820	CLIFTON LIME PLANT	LHOIST NORTH AMERICA OF TEXAS, LTD.	TX	4335A AND PSDTX31M1	327410	4/28/2017	Rotary Lime Kiln without a preheater	lime kiln	coal	219000	t/yr	Sulfur Dioxide (SO2)	fuel sulfur limits	12.8	LB/TON LIME		BACT-PSD	0			0		
WI-0233	CLM - SUPERIOR	CUTLER-MAGNER COMPANY	WI	05-DCF-412	327410	8/16/2006	LIME MANUFACTURING	LIME KILN (P50)	COAL / PET COKE	650	T/D	Sulfur Dioxide (SO2)	HIGH TEMPERATURE MEMBRANE (PTFE) FABRIC FILTER BAGHOUSE; PREHEATER LIME KILN. 2% FUEL SULFUR LIMIT (FOR COAL OR COAL / PET COKE BLEND).	33.7	LB/H	3 HOUR AVG.	BACT-PSD	2	% S	WT % S	0.62	LB/T	24 HOUR AVG.

ArcelorMittal Indiana Harbor East
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emissions Control
Appendix A: EPA RACT BACT LAER Clearinghouse Data
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
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	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	NATURAL GAS	169	MMBTU/H	Nitrogen Oxides (NOx)		0.085	LB/MMBTU		BACT-PSD	0.51	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	NATURAL GAS	169	MMBTU/H	Nitrogen Oxides (NOx)	UNLB WITH EGR	0.11	LB/MMBTU		BACT-PSD	1.82	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	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	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-	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	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	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		
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	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	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	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	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		

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Regional Haze Four-Factor Analyses for NO_X and SO_2 Emissions Control
Appendix A: EPA RACT BACT LAER Clearinghouse Data
Sinter Plant

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	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
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	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

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Regional Haze Four-Factor Analyses for NO_X and SO_2 Emissions Control
Appendix A: EPA RACT BACT LAER Clearinghouse Data
Sinter Plant

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	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	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	
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	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	

Appendix B

Air Permit Summary for II&S Mills

ArcelorMittal Indiana Harbor East

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

Appendix B: Air Permit Summary for II&S Mills

	Lime Plant			
	Emission Unit Description	Controls	NOx Limit	Comments
AM Indiana Harbor East	1973 No. 1 Lime Plant 569,400 tons/yr lime Two rotary kilns Maximum heat input 284 mmBtu/hr each	Baghouses	None	Listed controls are only for PM

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

Appendix B: Air Permit Summary for II&S Mills

	Strip Mill Furnace			
	Emission Unit Description	**Controls**	**NOx Limit**	**Comments**
AM Indiana Harbor East	2001 No. 4 Walking Beam Furnace 720 MMBtu/hr max HI (ea.) Natural Gas	Low-NOx burners	357 lb/MMSCF	Prevention of Significant Deterioration (PSD) and Emission Offset Minor Limit [326 IAC 2-2][326 IAC 2-3]: Total for all furnaces
	1995 No. 5 Walking Beam Furnace 685.6 MMBtu/hr max HI (ea.) Natural Gas	None		
	1995 No. 6 Walking Beam Furnace 685.6 MMBtu/hr max HI (ea.) Natural Gas	None		
AM Indiana Harbor West	1968 No. 1 Reheat Furnace 427 MMBtu/hr max HI (ea.) Natural Gas	None	None	
	1968 No. 2 Reheat Furnace 427 MMBtu/hr max HI (ea.) Natural Gas	None	None	
	1968 No. 3 Reheat Furnace 427 MMBtu/hr max HI (ea.) Natural Gas	None	None	
AM Burns Harbor	1966 Reheat Furnace No. 1 730 MMBtu/hr max HI (ea.) natural gas, coke oven gas, and/or propane	None	None	
	1966 Reheat Furnace No. 2 730 MMBtu/hr max HI (ea.) natural gas, coke oven gas, and/or propane	None	None	
	1966 Reheat Furnace No. 3 730 MMBtu/hr max HI (ea.) natural gas, coke oven gas, and/or propane	None	None	
	Approved in 2017 - HSM WBF No. 1 820 MMBtu/hr max HI (ea.) Natural Gas	Low-NOx burners	None	
	Approved in 2017 - HSM WBF No. 2 820 MMBtu/hr max HI (ea.) Natural Gas	Low-NOx burners	None	
USS Gary Works	RMF10500 Reheat Furnace No. 1 (Hot Strip Mill Furnace) 600 MMBtu/hr max HI (ea.) Natural gas	None	None	
	RMF20501 Reheat Furnace No. 2 (Hot Strip Mill Furnace) 600 MMBtu/hr max HI (ea.) Natural gas	None	None	
	RMF30502 Reheat Furnace No. 3 (Hot Strip Mill Furnace) 600 MMBtu/hr max HI (ea.) Natural gas	None	None	
	RMF40503 Reheat Furnace No. 4 (Hot Strip Mill Furnace) 600 MMBtu/hr max HI (ea.) Natural gas	None	None	

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

Appendix B: Air Permit Summary for II&S Mills

	Strip Mill Furnace			
	Emission Unit Description	Controls	NOx Limit	Comments
Nucor St. James	Facility does not have a strip mill			
USS Clairton	Facility does not have a strip mill			
AK Dearborn	1/1/1979 EUREHEATFURN1 - slab reheat furnace 1 oil shall not be used 1/1/1974 EUREHEATFURN2 - slab reheat furnace 2 oil shall not be used 1/1/1974 EUREHEATFURN3 - slab reheat furnace 3 oil shall not be used	None	0.11 lbs/MMBtu	R 336.2081 (ee) / 336.2082(4) -- PSD
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	
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)
AM Cleveland	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 a strip mill			
USS East Chicago	Facility does not have a strip mill			

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

Appendix B: Air Permit Summary for II&S Mills

	Sinter Plant			
	Emission Unit Description	**Controls**	**NOx Limit**	**Comments**
AM Indiana Harbor East	1959 Sinter Plant 1.4 Mmton/yr input	One (1) sinter plant windbox, controlled by the main baghouse with emissions exhausting through stack 7. One (1) sinter plant discharge end, controlled by the discharge end baghouse, and one (1) cooler station, partially controlled by the discharge end baghouse, with emissions exhausting through stack 8, installed in 1959.	None	Listed controls are only for PM
AM Burns Harbor	1968 Continuous Sintering Process Plant 535 tons sinter/hr	Twelve (12) windboxes, collectively identified as EU520-05, with emissions exhausting through one (1) multiclone, consisting of eight (8) cyclones followed in series by one (1) Venturi scrubber and mist eliminator, collectively identified as C520-3503, with VOC emissions monitored by a Continuous Emissions Monitor System (CEMS), exhausting at stack EP520-3513	None	
USS Gary Works	ISS10379 Sinter Strand (No. 3 Sinter Plant) 225 tons sinter/hr 50 mmbtu/hr (burners combined) - natural gas	Windbox Gas Cleaning Systems IS3203 & IS3204 (Quench Reactor, Dry Venturi Scrubber, baghouse - in series)	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
	ISS30381 Sinter Strand (No. 3 Sinter Plant) 225 tons sinter/hr 50 mmbtu/hr (burners combined) - natural gas	Windbox Gas Cleaning Systems IS3203 & IS3204 (Quench Reactor, Dry Venturi Scrubber, baghouse - in series)	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
Nucor St. James	Not constructed Sinter Plant 3.03 Mmtons/yr Natural gas	Lime Spray Drying Scrubber	0.495 lb/ton finished sinter	LAC 33:III.509
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			

ArcelorMittal Indiana Harbor East

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

Appendix B: Air Permit Summary for II&S Mills

	Boilers			
	Emission Unit Description	**Controls**	**SO2 Limit**	**Comments**
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
	1976 No. 502 Boiler 520 MMBtu/hr max HI (ea.) Natural Gas, Blast Furnace Gas	None		
	1976 No. 503 Boiler 520 MMBtu/hr max HI (ea.) Natural Gas, Blast Furnace Gas	None		
	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
	1956 No. 6 Boiler 454 MMBtu/hr max HI (ea.) Natural Gas, blast furnace gas	None		
	1956 No. 7 Boiler 454 MMBtu/hr max HI (ea.) Natural Gas, blast furnace gas	None		
	1967 No. 8 Boiler 1,090 MMBtu/hr max HI (ea.) Natural Gas, blast furnace gas	None		
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	
	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		
	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		
	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		
	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		
	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		
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.
	Not Constructed - Topgas Boiler No. 2 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low sulfur fuels		
	Not Constructed - Topgas Boiler No. 3 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low sulfur fuels		
	Not Constructed - Topgas Boiler No. 4 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low sulfur fuels		
	Not Constructed - Topgas Boiler No. 5 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low sulfur fuels		
	Not Constructed - Topgas Boiler No. 6 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low sulfur fuels		
	Not Constructed - Topgas Boiler No. 7 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low sulfur fuels		
	Not Constructed - Topgas Boiler No. 8 436.61 MMBtu/hr Natural Gas, blast furnace gas	Low sulfur fuels		

ArcelorMittal Indiana Harbor East
Regional Haze Four-Factor Analysis for NO_X and SO_2 Emissions Control
Appendix B: Air Permit Summary for II&S Mills

	Boilers			
	Emission Unit Description	**Controls**	**SO2 Limit**	**Comments**
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	
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)
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	1.10 lbs/MMBtu	OAC rule citation(s)
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	1.10 lbs/MMBtu	OAC rule citation(s)
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	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	

ArcelorMittal Indiana Harbor East
Regional Haze Four-Factor Analysis 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 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	
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.
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 Indiana Harbor East

Regional Haze Four-Factor Analysis 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			
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			

ArcelorMittal Indiana Harbor East

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

Appendix B: Air Permit Summary for II&S Mills

	Lime Plant			
	Emission Unit Description	Controls	SO2 Limit	Comments
AM Indiana Harbor East	1973 No. 1 Lime Plant 569,400 tons/yr lime	Baghouses	0.46 lb/MMBtu 32.1 lb/hr	326 IAC 7-4.1-11(a) Listed controls are only for PM

ArcelorMittal Indiana Harbor East

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

Appendix B: Air Permit Summary for II&S Mills

	Sinter Plant			
	Emission Unit Description	**Controls**	**SO2 Limit**	**Comments**
AM Indiana Harbor East	1959 Sinter Plant 1.4 Mmton/yr input	One (1) sinter plant windbox, controlled by the main baghouse with emissions exhausting through stack 7. One (1) sinter plant discharge end, controlled by the discharge end baghouse, and one (1) cooler station, partially controlled by the discharge end baghouse, with emissions exhausting through stack 8, installed in 1959.	180 lb/hr	Pursuant to 326 IAC 7-4.1-11(a)(13) Listed controls are only for PM.
AM Burns Harbor	1968 Continuous Sintering Process Plant 535 tons sinter/hr	Twelve (12) windboxes, collectively identified as EU520-05, with emissions exhausting through one (1) multiclone, consisting of eight (8) cyclones followed in series by one (1) Venturi scrubber and mist eliminator, collectively identified as C520-3503, exhausting at stack EP520-3513	None	
USS Gary Works	ISS10379 Sinter Strand (No. 3 Sinter Plant) 225 tons sinter/hr 50 mmbtu/hr (burners combined) - natural gas	Windbox Gas Cleaning Systems IS3203 & IS3204 (Quench Reactor, Dry Venturi Scrubber, baghouse - in series)	200 lb/hr	
	ISS30381 Sinter Strand (No. 3 Sinter Plant) 225 tons sinter/hr 50 mmbtu/hr (burners combined) - natural gas	Windbox Gas Cleaning Systems IS3203 & IS3204 (Quench Reactor, Dry Venturi Scrubber, baghouse - in series)	200 lb/hr	
Nucor St. James	Not constructed Sinter Plant 3.03 Mmtons/yr Natural gas	Lime Spray Drying Scrubber	2000 ppmv	LAC 33:III.1503.C: 3-hr average
			100 mg/DSCM	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 plant			

Appendix C

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

Appendix C.1

Walking Beam Furnace #5

ArcelorMittal Indiana Harbor East
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.1 – Table C.1-1: Cost Summary
Walking Beam Furnace #5
NO_x 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
Ultra-Low NOx Burners (ULNB)	39%	131.6	82.4	$5,133,000	$766,800	$9,300

ArcelorMittal Indiana Harbor East
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
Walking Beam Furnace #5

Operating Unit:	Walking Beam Furnace #5	**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
Sales Tax	7%			2020	Indiana sales tax rate
Interest Rate	5.50%				EPA SCR Control Cost Manual Spreadsheet
Contingencies	20%				Contingency based on study level estimate
Markup on capital investment (retrofit factor)	30%				EPA Cost Control Cost Manual Chapter 2
Operating Information					
Annual Op. Hrs	8,760	Hours			Assumed
Utilization Rate	100%				Assumed
Gross Heat Input from ULNBs	527.8	MMBTU/hr			Vendor estimate
Equipment Life	20	yrs			Assumed
Baseline Emissions	**Lb/Hr**	**Ton/Year**			
Nitrous Oxides (NOx)	48.9	214.0			Estimated annual emissions based on performance test data
ULNB - NO_x Performance	0.12	lb/MMBtu			Vendor guaranteed burner performance
Baseline NOx performance	0.20	lb/MMBtu			2018 performance test data lb/MMBtu average emission factor
Control efficiency	39%				

ArcelorMittal Indiana Harbor East

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

Appendix C.1 – Table C.1-3: NO_X Control - Ultra-Low NO_X Burners (ULNB)

Walking Beam Furnace #5

Operating Unit: **Walking Beam Furnace #5**

Desgin Capacity	528	MMBtu/hr
Expected Utiliztion Rate	100%	
Expected Annual Hours of Operation	8,760	Hours

CONTROL EQUIPMENT COSTS

Capital Costs		
Direct Capital Costs		
Purchased Equipment		1,111,000
Installation		2,287,000
Total Direct Capital Cost, DC		**3,398,000**
Total Indirect Capital Costs, IC		550,200
Total Capital Investment (TCI) = DC + IC		**3,948,200**
Total Capital Investment (TCI) with Retrofit Factor		**5,133,000**
Operating Costs		
Total Annual Direct Operating Costs	Labor, supervision, materials, replacement parts, utilities, etc.	82,500
Total Annual Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	684,300
Total Annual Cost (Annualized Capital Cost + Operating Cost)		**766,800**

Emission Control Cost Calculation

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)	214.0		0.12	131.6	82.4	9,300
Sulfur Dioxide (SO_2)		-			-	NA

Notes & Assumptions

1. Equipment costs and emission rates provided by burner vendor
2. Installation costs provided by ArcelorMittal based on projects of similar scope
3. Assumed 0.1 and 0.5 hr/shift respectively for operatior and maintenance labor
4. Controlled emission factor based on vendor guaranteed burner performance

ArcelorMittal Indiana Harbor East
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.1 – Table C.1-3: NO_X Control - Ultra-Low NO_X Burners (ULNB)
Walking Beam Furnace #5

CAPITAL COSTS
(Round to 1000s)

Direct Capital Costs			
Purchased Equipment			
Purchased Equipment Costs (A)			910,000
Instrumentation	10%	of purchased equipment costs	91,000
Sales Taxes	7.0%	of purchased equipment costs	64,000
Freight	5%	of purchased equipment costs	46,000
Purchased Equipment Total (B)	22%		**1,111,000**
Installation			
Materials and Refractory		Engineering Estimate	550,000
Mandrels for burner installation		Engineering Estimate	152,000
Scaffolding		Engineering Estimate	175,000
Demolition and Installation Labor		Engineering Estimate	1,400,000
Waste Disposal		Engineering Estimate	10,000
Installation Total			**2,287,000**
Total Direct Capital Cost, DC			**3,398,000**
Indirect Capital Costs			
Construction and Field Expenses	10%	of purchased equipment total	111,000
Contractor Fees	10%	of purchased equipment total	111,000
Start-up	5%	of purchased equipment total	56,000
Performance test		Estimate	50,000
Model Studies	NA	of purchased equipment total	NA
Contingencies	20%	of purchased equipment total	222,200
Total Indirect Capital Costs, IC			**550,200**
Total Capital Investment (TCI) = DC + IC			**3,948,200**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			**0**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**3,948,200**
Total Capital Investment (TCI) with Retrofit Factor	30%		**5,133,000**

OPERATING COSTS
(Round to 100s)

Direct Annual Operating Costs, DC			
Operating Labor			
Operator	67.53	$/Hr, 0.1 hr/8 hr shift, 8760 hr/yr	7,400
Supervisor	15%	15% of Operator Costs	1,100
Maintenance (2)			
Maintenance Labor	67.53	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr	37,000
Maintenance Materials	100%	of maintenance labor costs	37,000
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			**82,500**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	49,500
Administration (2% total capital costs)	2%	of total capital costs (TCI)	102,700
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	51,300
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	51,300
Capital Recovery	8%	for a 20- year equipment life and a 5.5% interest rate	429,500
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**684,300**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**766,800**

ArcelorMittal Indiana Harbor East
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.1 – Table C.1-3: NO_X Control - Ultra-Low NO_X Burners (ULNB)
Walking Beam Furnace #5

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.5%	
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	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

Walking Beam Furnace #6

ArcelorMittal Indiana Harbor East
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.2 – Table C.2-1: Cost Summary
Walking Beam Furnace #6
NO_x 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
Ultra-Low NOx Burners (ULNB)	46%	127.1	109.5	$5,133,000	$766,800	$7,000

ArcelorMittal Indiana Harbor East
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
Walking Beam Furnace #6

Operating Unit:	Walking Beam Furnace #6	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
Sales Tax	7%			2020	Indiana sales tax rate
Interest Rate	5.50%				EPA SCR Control Cost Manual Spreadsheet
Contingencies	20%				Contingency based on study level estimate
Markup on capital investment (retrofit factor)	30%				EPA Cost Control Cost Manual Chapter 2
Operating Information					
Annual Op. Hrs	8,760	Hours			Assumed
Utilization Rate	100%				Assumed
Gross Heat Input from ULNBs	527.8	MMBTU/hr			Vendor estimate
Equipment Life	20	yrs			Assumed
Baseline Emissions	**Lb/Hr**	**Ton/Year**			
Nitrous Oxides (NOx)	54.0	236.6			Estimated annual emissions based on performance test data
ULNB - NO_x Performance	0.12	lb/MMBtu			Vendor guaranteed burner performance
Baseline NOx performance	0.23	lb/MMBtu			2018 performance test data lb/MMBtu average emission factor
Control efficiency	46%				

ArcelorMittal Indiana Harbor East
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.2 – Table C.2-3: NO_X Control - Ultra-Low NO_X Burners (ULNB)
Walking Beam Furnace #6

Operating Unit: **Walking Beam Furnace #6**

Desgin Capacity	528	MMBtu/hr
Expected Utiliztion Rate	100%	
Expected Annual Hours of Operation	8,760	Hours

CONTROL EQUIPMENT COSTS

Capital Costs								
Direct Capital Costs								
Purchased Equipment								1,111,000
Installation								2,287,000
Total Direct Capital Cost, DC								**3,398,000**
Total Indirect Capital Costs, IC								550,200
Total Capital Investment (TCI) = DC + IC								**3,948,200**
Total Capital Investment (TCI) with Retrofit Factor								**5,133,000**
Operating Costs								
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.						82,500
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost						684,300
Total Annual Cost (Annualized Capital Cost + Operating Cost)								**766,800**

Emission Control Cost Calculation

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)	236.6		0.12	127.1	109.5	7,000
Sulfur Dioxide (SO_2)		-			-	NA

Notes & Assumptions

1 Equipment costs and emission rates provided by burner vendor
2 Installation costs provided by ArcelorMittal based on projects of similar scope
3 Assumed 0.1 and 0.5 hr/shift respectively for operatior and maintenance labor
4 Controlled emission factor based on vendor guaranteed burner performance

ArcelorMittal Indiana Harbor East
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.2 – Table C.2-3: NO_X Control - Ultra-Low NO_X Burners (ULNB)
Walking Beam Furnace #6

CAPITAL COSTS
(Round to 1000s)

Direct Capital Costs			
Purchased Equipment			
Purchased Equipment Costs (A)			910,000
Instrumentation	10%	of purchased equipment costs	91,000
Sales Taxes	7.0%	of purchased equipment costs	64,000
Freight	5%	of purchased equipment costs	46,000
Purchased Equipment Total (B)	22%		**1,111,000**
Installation			
Materials and Refractory		Engineering Estimate	550,000
Mandrels for burner installation		Engineering Estimate	152,000
Scaffolding		Engineering Estimate	175,000
Demolition and Installation Labor		Engineering Estimate	1,400,000
Waste Disposal		Engineering Estimate	10,000
Installation Total			**2,287,000**
Total Direct Capital Cost, DC			**3,398,000**
Indirect Capital Costs			
Construction and Field Expenses	10%	of purchased equipment total	111,000
Contractor Fees	10%	of purchased equipment total	111,000
Start-up	5%	of purchased equipment total	56,000
Performance test		Estimate	50,000
Model Studies	NA	of purchased equipment total	NA
Contingencies	20%	of purchased equipment total	222,200
Total Indirect Capital Costs, IC			**550,200**
Total Capital Investment (TCI) = DC + IC			**3,948,200**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			**0**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**3,948,200**
Total Capital Investment (TCI) with Retrofit Factor	30%		**5,133,000**

OPERATING COSTS
(Round to 100s)

Direct Annual Operating Costs, DC			
Operating Labor			
Operator	67.53	$/Hr, 0.1 hr/8 hr shift, 8760 hr/yr	7,400
Supervisor	15%	15% of Operator Costs	1,100
Maintenance (2)			
Maintenance Labor	67.53	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr	37,000
Maintenance Materials	100%	of maintenance labor costs	37,000
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			**82,500**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	49,500
Administration (2% total capital costs)	2%	of total capital costs (TCI)	102,700
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	51,300
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	51,300
Capital Recovery	8%	for a 20- year equipment life and a 5.5% interest rate	429,500
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**684,300**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**766,800**

ArcelorMittal Indiana Harbor East
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.2 – Table C.2-3: NO_X Control - Ultra-Low NO_X Burners (ULNB)
Walking Beam Furnace #6

Capital Recovery Factors		
Primary Installation		
Interest Rate	5.5%	
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	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

Sinter Plant Windbox

ArcelorMittal Indiana Harbor East
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.3 - Table C.3-1: Cost Summary
Sinter Plant Windbox

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%	37.1	333.9	$37,871,432	$9,651,032	$28,904
Dry Sorbent Injection (DSI)	70%	111.3	259.7	$30,433,986	$9,923,945	$38,200

ArcelorMittal Indiana Harbor East

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

Sinter Plant Windbox

Operating Unit:	Sinter Plant Windbox	**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	200.00	$/ton		2020	Solid waste disposal cost estimated by ArcelorMittal. Material captured in baghouse would be hazardous.	
Contingencies	10%	of purchased equip cost (B)			EPA Cost Control Cost Manual Chapter 2	Suggested contingency range of 5% to 15% of total capital investment
Markup on capital investment (retrofit factor)	50%				EPA Cost Control Cost Manual Chapter 2	
Operating Information						
Annual Op. Hrs	6,558	Hours			Emission Inventory Data	
Utilization Rate	100%				Assumed	
Design Capacity		MMBTU/hr			Boiler Design Capacity	
Equipment Life	20	yrs			Assumed	
Temperature	163	Deg F			Performance test data	
Moisture Content	4.2%				Performance test data	
Actual Flow Rate	484,000	acfm			Performance test data	
Standardized Flow Rate	410,196	scfm @ 68° F	382,228	scfm @ 32° F	Calculated Value	
Dry Std Flow Rate	391,000	dscfm @ 68° F			Performance test data	
Plant Elevation	610	Feet above sea level			Plant elevation	
	Baseline Emissions					
Pollutant	**Lb/Hr**	**Ton/Year**				
Sulfur Dioxides (SO2)	113.1	371.0			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	
DSI - SO_2 Control Efficiency	70%				Control efficiency is based on trona as injected reagent.	

ArcelorMittal Indiana Harbor East
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.3 - Table C.3-3: SO_2 Control Spray Dry Absorber (SDA)
Sinter Plant Windbox

Operating Unit: **Sinter Plant Windbox**

Emission Unit Number			Stack/Vent Number		
Design Capacity		MMBtu/hr	Standardized Flow Rate	382,228	scfm @ 32º F
Utilization Rate	100%		Temperature	163	Deg F
Annual Operating Hours	6,558	Hours	Moisture Content	4.2%	
Annual Interest Rate	5.5%		Actual Flow Rate	484,000	acfm
Equipment Life	20	yrs	Standardized Flow Rate	410,196	scfm @ 68º F
			Dry Std Flow Rate	391,000	dscfm @ 68º F

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			**447,576**
Purchased Equipment Total (B)	22%	of control device cost (A)	**8,426,001**
Installation - Standard Costs	74%	of purchased equip cost (B)	6,235,241
Installation - Site Specific Costs			NA
Installation Total			6,235,241
Total Direct Capital Cost, DC			14,661,242
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	4,381,521
Total Capital Investment (TCI) = DC + IC			**37,871,432**
Adjusted TCI for Replacment Parts			**37,336,504**
SDA/Baghouse TCI with Retrofit Factor			**56,004,757**
Reheat TCI			**1,034,598**
Operating Costs			
Total Annual Direct Operating Costs (SDA + Reheat)		Labor, supervision, materials, replacement parts, utilities, etc.	2,203,032
Total Annual Indirect Operating Costs (SDA + Reheat)		Sum indirect oper costs + capital recovery cost	7,448,000
Total SDA + Reheat Annual Cost (Annualized Capital Cost + Operating Cost)			**9,651,032**

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)		371.0	90%			37.1	333.9	28,904
Sulfuric Acid Mist						0.00	-	NA
Fluorides						0.0	-	NA
Volatile Organic Compounds (VOC)						0.0	-	NA
Carbon Monoxide (CO)						0.0	-	NA
Lead (Pb)						0.00	-	NA

Notes & Assumptions

1 SDA cost is installed included in TCI total. Cost from another Barr Engineering project 2011 (712,400 scfm)
2 Baghouse capital cost estimate based on EPA-R05-OAR-2010-0954-0079, ancillary equipment from other Barr Engineering projects
3 Costs scaled to design airflow using the 6/10 power law
4 Cost scaled up for inflation using the Chemical Engineering Plant Cost Index (CEPCI)
5 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1
6 The existing flue gas is too moist for spray dryers, reheat is required to prevent condensation on filter bags

ArcelorMittal Indiana Harbor East
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.3 - Table C.3-3: SO2 Control Spray Dry Absorber (SDA)
Sinter Plant Windbox

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) [1]		***Baghouse and ancillaries cost only (SDA included in TCI) >>>***	**6,906,558**
Purchased Equipment Costs (A) - Absorber + packing + auxiliary equipment, EC			
Instrumentation	10%	of control device cost (A)	690,656
State Sales Taxes	7.0%	of control device cost (A)	483,459
Freight	5%	of control device cost (A)	345,328
Purchased Equipment Total (B)	22%		**8,426,001**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	337,040
Handling & erection	50%	of purchased equip cost (B)	4,213,001
Electrical	8%	of purchased equip cost (B)	674,080
Piping	1%	of purchased equip cost (B)	84,260
Insulation	7%	of purchased equip cost (B)	589,820
Painting	4%	of purchased equip cost (B)	337,040
Installation Subtotal Standard Expenses	74%		**6,235,241**
Other Specific Costs	N/A	Site Specific	-
	N/A	Site Specific	-
	N/A	Site Specific	-
Total Site Specific Costs			NA
Installation Total			**6,235,241**
Total Direct Capital Cost, DC			**14,661,242**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	842,600
Construction & field expenses	20%	of purchased equip cost (B)	1,685,200
Contractor fees	10%	of purchased equip cost (B)	842,600
Start-up	1%	of purchased equip cost (B)	84,260
Performance test	1%	of purchased equip cost (B)	84,260
Model Studies	N/A	of purchased equip cost (B)	-
Contingencies	10%	of purchased equip cost (B)	842,600
Total Indirect Capital Costs, IC	52%	of purchased equip cost (B)	**4,381,521**
Total Capital Investment (TCI) = DC + IC		***SDA installed cost included here >>>***	**37,871,432**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**37,336,504**
Total Capital Investment (TCI) with Retrofit Factor	50%		**56,004,757**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	67.53	$/Hr, 2.0 hr/8 hr shift, 6558 hr/yr, 100% utilization	110,716
Supervisor	15%	of Op., 0.0 , 6558 hr/yr, 100% utilization	16,607
Maintenance			
Maintenance Labor	67.53	$/Hr, 1.0 hr/8 hr shift, 6558 hr/yr, 100% utilization	55,358
Maintenance Materials	100%	of maintenance labor costs	55,358
Utilities, Supplies, Replacements & Waste Management			
Electricity	0.07	$/kwh, 876.0 kW-hr, 6558 hr/yr, 100% utilization	419,247
Compressed Air	0.48	$/kscf, 2.0 scfm/kacfm, 6558 hr/yr, 100% utilization	183,349
N/A			-
SW Disposal	200.00	$/ton, 0.1 ton/hr, 6558 hr/yr, 100% utilization	148,430
Lime	183.68	$/ton, 153.1 lb/hr, 6558 hr/yr, 100% utilization	92,209
Filter Bags	228.02	$/bag, 1,925 bags, 6558 hr/yr, 100% utilization	198,273
N/A			
N/A			-
N/A			-
N/A			-
N/A			-
N/A			-
N/A			-
N/A			-
Total Annual Direct Operating Costs			**1,279,549**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	142,824
Administration (2% total capital costs)	2%	of total capital costs (TCI)	1,120,095
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	560,048
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	560,048
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	4,884,714
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**7,267,728**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**8,547,277**

ArcelorMittal Indiana Harbor East
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.3 - Table C.3-3: SO2 Control Spray Dry Absorber (SDA)
Sinter Plant Windbox

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	1925		
Total Rep Parts Cost	491,597	Cost adjusted for freight & sales tax	
Installation Labor	43,331	10 min per bag	EPA Cont Cost Manual 6th ed Section 6 Chapter 1.5.1.4
Total Installed Cost	**534,928**		
Annualized Cost	**198,273**		

Electrical Use

	Flow acfm	D P in H2O	Efficiency	Hp	kW	
Blower, Baghouse	484,000	10.00			5,745,070	Incremental electricity increase over with baghouse replacing scrubber including ducting
Total					5,745,070	

Reagents and Other Operating Costs

Lime Use Rate	1.30	lb-mole CaO/lb-mole SO2	153.10 lb/hr Lime
Solid Waste Disposal	742	ton/yr GSA unreacted sorbent and reaction byproducts	

Operating Cost Calculations

Utilization Rate	100%	Annual Operating Hours		6,558			
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	67.53	$/Hr	2.0	hr/8 hr shift	1,640	$ 110,716	$/Hr, 2.0 hr/8 hr shift, 6558 hr/yr, 100% utilization
Supervisor	15%	of Op.			NA	$ 16,607	of Op., 0.0 , 6558 hr/yr, 100% utilization
Maintenance							
Maint Labor	67.53	$/Hr	1.0	hr/8 hr shift	820	$ 55,358	$/Hr, 1.0 hr/8 hr shift, 6558 hr/yr, 100% utilization
Maint Mtls	100	% of Maintenance Labor			NA	$ 55,358	% of Maintenance Labor, 0.0 , 6558 hr/yr, 100% utilization
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.073	$/kwh	876.0	kW-hr	5,745,070	$ 419,247	$/kwh, 876.0 kW-hr, 6558 hr/yr, 100% utilization
Compressed Air	0.481	$/kscf	2	scfm/kacfm	380,889	$ 183,349	$/kscf, 2.0 scfm/kacfm, 6558 hr/yr, 100% utilization
Water	5.129	$/mgal		gpm			$/mgal, 0 gpm, 6558 hr/yr, 100% utilization
SW Disposal	200.00	$/ton	0.11	ton/hr	742	$ 148,430	$/ton, 0.1 ton/hr, 6558 hr/yr, 100% utilization
Lime	183.68	$/ton	153.1	lb/hr	502	$ 92,209	$/ton, 153.1 lb/hr, 6558 hr/yr, 100% utilization
Filter Bags	228.02	$/bag	1,925	bags	N/A	$ 198,273	$/bag, 1,925 bags, 6558 hr/yr, 100% utilization

ArcelorMittal Indiana Harbor East

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

Appendix C.3 - Table C.3-4: Flue Gas Reheat for SDA

Sinter Plant Windbox

Operating Unit: **Sinter Plant Windbox**

Emission Unit Number			Stack/Vent Number			**Chemical Engineering**
Desgin Capacity		MMBTU/hr	Standardized Flow Rate	382,228	scfm @ 32º F	**Chemical Plant Cost Index**
Expected Utilization Rate	100%		Temperature	163	Deg F	1998/1999 390
Expected Annual Hours of Operation	6,558	Hours	Moisture Content	4.2%		2019 607.5
Annual Interest Rate	5.5%		Actual Flow Rate	484,000	acfm	Inflation Adj 1.56
Expected Equipment Life	20	yrs	Standardized Flow Rate	410,196	scfm @ 68º F	
			Dry Std Flow Rate	391,000	dscfm @ 68º F	

CONTROL EQUIPMENT COSTS

Capital Costs			
Direct Capital Costs			
Purchased Equipment (A)			336,520
Purchased Equipment Total (B)	22%	of control device cost (A)	**410,555**
Installation - Standard Costs	30%	of purchased equip cost (B)	123,166
Installation - Site Specific Costs			NA
Installation Total			123,166
Total Direct Capital Cost, DC			533,721
Total Indirect Capital Costs, IC	38%	of purchased equip cost (B)	156,011
Total Capital Investment (TCI) = DC + IC			**689,732**
TCI with Retrofit Factor			**1,034,598**
Operating Costs			
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.	923,484
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	180,272
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,103,755**

Notes & Assumptions

1 Equipment cost estimate EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 3.2 Chapter 2.5.1
2 Calculations per EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 3.2 Chapter 2

ArcelorMittal Indiana Harbor East

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

Appendix C.3 - Table C.3-4: Flue Gas Reheat for SDA

Sinter Plant Windbox

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (A) (1)			**336,520**
Purchased Equipment Costs (A)			
Instrumentation	10%	of control device cost (A)	33,652
MN Sales Taxes	7.0%	of control device cost (A)	23,556
Freight	5%	of control device cost (A)	16,826
Purchased Equipment Total (B)	22%		**410,555**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	32,844
Handling & erection	14%	of purchased equip cost (B)	57,478
Electrical	4%	of purchased equip cost (B)	16,422
Piping	2%	of purchased equip cost (B)	8,211
Insulation	1%	of purchased equip cost (B)	4,106
Painting	1%	of purchased equip cost (B)	4,106
Installation Subtotal Standard Expenses	30%		**123,166**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Site Specific - Other		Site Specific	NA
Total Site Specific Costs			NA
Installation Total			**123,166**
Total Direct Capital Cost, DC			**533,721**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	41,055
Construction & field expenses	5%	of purchased equip cost (B)	20,528
Contractor fees	10%	of purchased equip cost (B)	41,055
Start-up	2%	of purchased equip cost (B)	8,211
Performance test	1%	of purchased equip cost (B)	4,106
Model Studies		of purchased equip cost (B)	0
Contingencies	10%	of purchased equip cost (B)	41,055
Total Indirect Capital Costs, IC	38%	of purchased equip cost (B)	**156,011**
Total Capital Investment (TCI) = DC + IC			**689,732**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**689,732**
Total Capital Investment (TCI) with Retrofit Factor	50%		**1,034,598**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	67.53	$/Hr, 0.5 hr/8 hr shift, 6558 hr/yr	27,679
Supervisor	15%	15% of Operator Costs	4,152
Maintenance			
Maintenance Labor	67.53	$/Hr, 0.5 hr/8 hr shift, 6558 hr/yr	27,679
Maintenance Materials	100%	of maintenance labor costs	27,679
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
Natural Gas	6.15	$/mscf, 345 scfm, 6558 hr/yr, 100% utilization	836,294
Total Annual Direct Operating Costs			**923,484**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	52,313
Administration (2% total capital costs)	2%	of total capital costs (TCI)	20,692
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	10,346
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	10,346
Capital Recovery	0.0837	for a 20- year equipment life and a 5.5% interest rate	86,574
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**180,272**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,103,755**

ArcelorMittal Indiana Harbor East
Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.3 - Table C.3-4: Flue Gas Reheat for SDA
Sinter Plant Windbox

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

Replacement Catalyst:	**Catalyst**	
Equipment Life	3	years
CRF	0.3707	
Rep part cost per unit	0	$\$/ft^3$
Amount Required	39	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	**Zero out if no replacement parts needed**
Annualized Cost	**0**	

Replacement Parts & Equipment:			
Equipment Life	3		
CRF	0.3707		
Rep part cost per unit	0	$ each	
Amount Required	0	Number	
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax	
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr	OAQPS list replacement times from 5 - 20 min per bag.
Total Installed Cost	**0**	**Zero out if no replacement parts needed**	
Annualized Cost	**0**		

Electrical Use	Flow acfm		Δ P in H2O	Efficiency	Hp	kW	
Blower, Thermal	484,000		19	0.6		1,793.2	EPA Cost Cont Manual 6th ed - Oxidizders Chapter 2.5.2.1
Blower, Catalytic	484,000		23	0.6		2,170.7	EPA Cost Cont Manual 6th ed - Oxidizders Chapter 2.5.2.1
Oxidizer Type	**thermal**	(catalytic or thermal)				0.0	N/A - Reheat is a duct burner, negligible presssure drop

Reagent Use & Other Operating Costs Oxidizers - NA

Operating Cost Calculations — **Annual hours of operation:** **6,558**; **Utilization Rate:** **100%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	67.53	$/Hr	0.5	hr/8 hr shift	410	27,679	$/Hr, 0.5 hr/8 hr shift, 6558 hr/yr
Supervisor	15%	of Op.			NA	4,152	15% of Operator Costs
Maintenance							
Maint Labor	67.53	$/Hr	0.5	hr/8 hr shift	410	27,679	$/Hr, 0.5 hr/8 hr shift, 6558 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	27,679	100% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management							
Electricity	0.073	$/kwh	0.0	kW-hr	0	0	$/kwh, 0 kW-hr, 6558 hr/yr, 100% utilization
Natural Gas	6.15	$/mscf	345	scfm	135,939	836,294	$/mscf, 345 scfm, 6558 hr/yr, 100% utilization

*annual use rate is in same units of measurement as the unit cost factor

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Regional Haze Four-Factor Analyses for NO_X and SO_2 Emission Controls
Appendix C.3 - Table C.3-4: Flue Gas Reheat for SDA
Sinter Plant Windbox

Flue Gas Re-Heat Equipment Cost Estimate Basis Thermal Oxidizer with 70% Heat Recovery

Auxiliary Fuel Use Equation 3.19

T_{wi}	163	Deg F - Temperature of waste gas into heat recovery
T_{fi}	193	Deg F - Temperature of Flue gas into heat recovery
T_{ref}	77	Deg F - Reference temperature for fuel combustion calculations
FER	0%	Factional Heat Recovery % Heat recovery section efficiency
T_{wo}	163	Deg F - Temperature of waste gas out of heat recovery
T_{fo}	193	Deg F - Temperature of flue gas out of heat recovery
$-h_{caf}$	21502	Btu/lb Heat of combustion auxiliary fuel (methane)
$-h_{wg}$	0	Btu/lb Heat of combustion waste gas
$C_{p\ wg}$	0.2400	Btu/lb - Deg F Heat Capacity of waste gas (air)
ρ_{wg}	0.0739	lb/scf - Density of waste gas (air) at 77 Deg F
ρ_{af}	0.0408	lb/scf - Density of auxiliary fuel (methane) at 77 Deg F
Q_{wg}	410,196	scfm - Flow of waste gas
Q_{af}	345	scfm - Flow of auxiliary fuel

Year 2005 Inflation Rate 3.0%

Cost Calculations 410,541 scfm Flue Gas — Cost in 1989 $'s $216,038

Current Cost Using CHE Plant Cost Index $336,520

Heat Rec %	A	B	
0	10,294	0.2355	Exponents per equation 3.24
0.3	13,149	0.2609	Exponents per equation 3.25
0.5	17,056	0.2502	Exponents per equation 3.26
0.7	21,342	0.2500	Exponents per equation 3.27

Reference: OAQPS Control Cost Manual 5th Ed Feb 1996 - Chapter 3 Thermal & Catalytic Incinerators (EPA 453/B-96-001)