

INDIANA
REGIONAL HAZE
STATE IMPLEMENTATION PLAN
FOR THE
SECOND IMPLEMENTATION PERIOD

Prepared by:
Indiana Department of Environmental Management
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ACRONYMS/ABBREVIATIONS LIST

AFGD	Advanced Flue Gas Desulfurization
AoI	Area of Influence
AP-42	Air Pollution Factors Reference
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
CAMD	Clean Air Markets Division
CaO	Lime
CaSO ₃	Calcium Sulfate
CaSO ₄	Calcium Sulfate
CEMS	Continuous Emissions Monitoring System
CENRAP	Central States Air Resource Agencies
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
CPI	Consumer Price Index
CS ₂	Carbon Disulfide
CSAPR	Cross State Air Pollution Rule
CWPB1	Center-Worked Prebake One
D.C.	District of Columbia
DSI	Dry Sorbent Injection
EGU	Electric Generating Units
EPA	United States Environmental Protection Agency
ERTAC	Eastern Regional Technical Advisory Committee
ESP	Electric Static Precipitator
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
H ₂ S	Hydrogen Sulfide
HAPs	Hazardous Air Pollutants
HCl	Hydrochloric Acid
HRSGs	Heat Recovery Steam Generators
IAC	Indiana Administrative Code

IDEM	Indiana Department of Environmental Management
IMPROVE	Interagency Monitoring of Protected Visual Environments
IPM	Integrated Planning Model
IRP	Integrated Resource Plan
LADCO	Lake Michigan Air Directors Consortium
LAER	Lowest Achievable Emission Rate
LTS	Long Term Strategy
lbs/hr	Pounds Per Hour
lb/MMscf	Pound Per Million Standard Cubic Foot
lb/MMBtu	Pound Per Million British Thermal Units
LHWF	Liquid Hazardous Waste Fuel
LNB	Low NO _x Burners
MACT	Maximum Achievable Control Technology
MANE-VU	Mid-Atlantic/Northeast Visibility Union
MARAMA	Mid-Atlantic Regional Air Management Association
MMBtu	Million British Thermal Unit
MMBtu/hr	Million British Thermal Unit Per Hour
NAAQS	National Ambient Air Quality Standards
NaOH	Sodium Hydroxide
NH ₃	Ammonia
NESHAPs	National Emission Standards for Hazardous Air Pollutants
NEEDS	National Electric Energy Demand System
NG	Natural Gas
NO _x	Nitrogen Oxides
NSPS	New Source Performance Standards
PSAT	Particulate Matter Source Apportionment Tool
Petcoke	Petroleum Derived Coke
PM	Particulate Matter
ppm	Parts Per Million
PSD	Prevention of Significant Deterioration
RACT	Reasonably Available Control Technology
RAVI	Reasonable Attributable Visibility Impairment
RBLC	RACT/BACT/LAER Clearinghouse
RCRA	Resource Conservation and Recovery Act
RFI	Request for Information
RH	Regional Haze
RPGs	Reasonable Progress Goals
RPO	Regional Planning Organization
scf	Standard Cubic Foot
SCR	Selective Catalytic Reduction
SDA	Spray Dryer Absorption
SESARM	Southeastern Air Pollution Control Agencies
SIP	State Implementation Plan
SMOKE	Sparse Matrix Operator Kernel Emissions
SNCR	Selective Non-Catalytic Reduction
SO ₂	Sulfur Dioxide

SSM	Significant Source Modification
STG	Steam Turbine Generator
tons/yr	Tons Per Year
ULNB	Ultra-Low-NO _x Burners
URP	Uniform Rate of Progress
VISTAS	Visibility Improvement State and Tribal Association of the Southeast
VOC	Volatile Organic Compound
WBF	Walking Beam Furnace

1.0 INTRODUCTION

In the 1977 amendments to the Clean Air Act (CAA), Congress added Section 169 (42 U.S.C. 7491) setting forth the following national visibility goal in Section 169A: “Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution.” A mandatory Class I Federal area is one in which visibility is protected more stringently than under the national ambient air quality standards and includes national parks and wilderness areas of special national and cultural significance. There are 156 mandatory Class I Federal areas across the country. These protected areas are called “mandatory Class I Federal areas” in the CAA but are referred to in this document as “Class I areas.” The Regional Haze (RH) Rule addresses the combined visibility effects of various pollution sources over a wide geographic region. This wide-reaching pollution net means that many states, even those without Class I areas, are required to participate in haze reduction efforts.

The United States Environmental Protection Agency’s (EPA’s) RH Rule was adopted and published in the Federal Register (FR) on July 1, 1999 (64 FR 35714) and went into effect on August 30, 1999. The RH Rule requires states to set reasonable progress goals (RPGs) toward meeting a national goal of natural visibility conditions in Class I areas by the year 2064. Section 51.308 of the RH Rule requires states to submit a series of state implementation plans (SIPs) to protect visibility in Class I areas. The RH Rule requires these states, in coordination with EPA, the Federal Land Managers (FLMs) consisting of the U.S. National Park Service, U.S. Fish and Wildlife Service, U.S. Forest Service, and other interested parties, to develop and implement air quality protection plans to reduce the pollution that causes visibility impairment in the Class I areas. States, tribes, and the five multi-jurisdictional regional planning organizations (RPOs) designated by EPA to assist with the coordination and cooperation needed to address the haze issue, worked together to develop the technical basis for these plans and comprehensive periodic revisions to the initial plans currently due in 2021, 2028, and every 10 years thereafter.

Indiana does not have any Class I areas; however, Indiana sources were determined to impact visibility in Class I areas in other states during the first planning period. The final version of Indiana’s RH SIP for the first implementation period was submitted on January 15, 2011 and supplemented with additional information on March 10, 2011. This submittal addressed the initial 10-year implementation period (i.e., reasonable progress by the year 2018). SIP requirements [pursuant to 40 Code of Federal Regulations (CFR) 51.308(d)] included establishing reasonable progress goals, determining baseline conditions, determining natural conditions, providing a long-term control strategy, providing a monitoring strategy (air quality and emissions), and establishing Best Available Retrofit Technology (BART) emissions limitations and associated compliance schedule. EPA issued a limited disapproval of the state's original RH plan on June 7, 2012 (77 FR 33642), due to the plan's reliance on the Clean Air Interstate Rule (CAIR) for emission reductions that would reduce Indiana’s visibility impacts at Class I areas. The District of Columbia Circuit Court remanded CAIR to EPA without vacatur on July 11, 2008. The court left CAIR because it found that "allowing CAIR to remain in effect

until it is replaced by a rule consistent with the court's opinion would at least temporarily preserve the environmental values covered by CAIR." Therefore, CAIR requirements remained in place and CAIR's regional control programs continued operating while EPA developed replacement rules in response to the remand.

On January 9, 2009, the EPA signed a FR notice making a finding of failure to submit all or a portion of their Regional Haze SIPs for 37 states, the District of Columbia, and the Virgin Islands. EPA initiated a 2-year deadline to issue a Federal Implementation Plan (FIP). The FIP provided the basic program requirements for each state that had not completed an approved plan of their own by January 15, 2011. The final version of Indiana's RH SIP for the first implementation period was submitted on January 15, 2011 and supplemented with additional information on March 10, 2011.

Indiana implemented the measures outlined in the RH SIP for the first implementation period by the date of the 5-year progress report. On March 30, 2016, the Indiana RH Five-Year Progress Report State Implementation Plan was submitted in accordance with the RH Rule requirements in 40 CFR 51.308 (g) and (h). The analyses conducted for the five-year progress report found that Class I Federal areas affected by emissions from Indiana were meeting or exceeding the RPGs for 2018. As such, the state determined that the state's RH SIP was adequate to meet Indiana's RPGs for the first implementation period and required no substantive revision at the time. This report was reviewed and approved by U.S. EPA on February 2, 2018 (83 FR 4847) as meeting the requirements of the Regional Haze Rule.

On September 6, 2019, EPA converted its limited approval/limited disapproval of Indiana's RH SIP to a full approval and withdrew the FIP provisions (84 FR 46889).

Pursuant to the requirements of 51.308(a) and (b), Indiana submits this SIP to meet the requirements of EPA's RH Rule that was adopted to comply with requirements set forth in the Clean Air Act. Elements of this SIP address the core requirements pursuant to 40 CFR 51.308(f). Indiana has developed this RH SIP in accordance with Indiana laws and rules, 326 Indiana Administrative Code (IAC), Article 26 - Regional Haze, and has the authority to implement the SIP in accordance with those laws and rules. Indiana has provided public notice of the opportunity to comment on the RH SIP and of the public hearing that will be held regarding the SIP. Public comments have been addressed and summarized in this document.

2.0 BACKGROUND

The RH Rule provides a regulatory framework within which states are required to develop and implement SIP revisions to improve and protect visibility in Class I areas and assure reasonable progress towards meeting the national goal. The states must address regional haze in each Class I area located within the state and in each Class I area located outside the state which may be affected by emissions from within the state. RH SIPs must include Class I area visibility improvement goals and emission management strategies needed to reach those goals.

In January 2017, EPA issued a final rule updating the RH program (82 FR 3078), including revising portions of the visibility protection rule promulgated in 1980 (45 FR 80084) and the RH Rule promulgated in 1999 (82 FR 3078). The revised rule governs states' obligations and EPA's review of periodic SIPs developed for the second and subsequent implementation periods. The 2017 revisions clarify the relationship between long term strategies and RPGs in SIPs and the long-term strategy (LTS) obligation of all states; and clarify and modify the requirements for periodic comprehensive revisions of SIPs, among other requirements.

As noted in the RH Reform Roadmap Memorandum, in January 2018, the EPA Administrator announced in a letter to several petitioners that EPA intends to commence a notice-and-comment rulemaking to revisit certain aspects of the January 2017 RH Rule update. The RH Reform Roadmap Memorandum indicated that such a rulemaking would impact future RH implementation periods.

The revised rule governs EPA review of periodic SIPs developed for the second and subsequent implementation periods and EPA review of progress reports submitted subsequent to those plans. A summary of key changes to the rule in 2017, including changes to 40 CFR 51.308(f), is provided below.

- Extension of the 2018 due date for SIPs - EPA extended the due date for the second implementation period RH SIPs, from July 31, 2018, to July 31, 2021. The second implementation period still ends in 2028.
- Relationship between the LTS and the RPGs - Clarified 1) the relationship between LTS and RPGs in state plans and 2) the LTS obligation of all states.
- Progress tracking - EPA revised the way in which some days during each year are to be selected as the 20 percent most impaired days and then used for purposes of tracking progress towards natural visibility conditions. This will focus attention on days when anthropogenic emissions impair visibility and away from days when wildfires and natural dust storms are the greatest contributors to reduced visibility.
- Possible adjustment of the uniform rate of progress (URP) for the impacts of anthropogenic sources outside the U.S. (i.e., international sources) and certain types of wildland prescribed fire - EPA added a provision that allows the agency to approve adjustments to the URP to reflect the impacts of these causes of visibility impairment, if an adjustment has been developed through scientifically valid data and methods. These adjustments would be developed and applied separately, although they would both be accomplished by adding an estimate of the impact of the relevant source type or types to the value of the natural visibility condition for the 20 percent most anthropogenically impaired days, for the purposes of calculating the URP. The wildland prescribed fires that are eligible under the RH Rule to be included in this adjustment are those conducted with the objective to establish, restore, and/or maintain sustainable and resilient wildland ecosystems, to reduce the risk of catastrophic wildfires, and/or to preserve endangered or threatened species during which appropriate basic smoke management practices were applied.

- Progress reports - EPA revised the due dates for progress reports and removed the requirement for progress reports to be SIP revisions for the second and subsequent implementation periods.
- Reasonably attributable visibility impairment (RAVI) - EPA updated, simplified, and extended to all states the provisions for RAVI. At the same time, EPA revoked existing FIPs implementing the 1980 RAVI requirements. Indiana does not have any certifications from FLMs for any of its sources therefore, RAVI does not apply.
- FLM consultation - EPA made changes to FLM consultation requirements.
- Monitoring strategy - EPA removed the requirement for progress reports submitted for the second and later implementation periods to re-address the monitoring strategy for RH. The requirement for periodic SIP revisions to re-address the monitoring strategy was retained.

EPA developed the “Guidance on Regional Haze State Implementation Plans for the Second Implementation Period”, dated August 2019 (EPA RH SIP Guidance Document) to help states develop approvable RH SIPs that are due to be submitted to EPA by July 31, 2021, for the second implementation period ending in 2028. EPA’s guidance document is intended to provide recommendations for use by states in developing SIP submissions, and for EPA Regional offices in acting on them.

Indiana has participated in extensive technical analyses conducted by the Lake Michigan Air Directors Consortium (LADCO), the Midwest region’s regional planning organization (RPO), to determine if any Class I areas have visibility impairment that may be caused by sources within the state for the second implementation period (see the LADCO Regional Haze Technical Support Document (TSD) for the Second Implementation Period dated June 17, 2021). The results of these analyses have determined that some Indiana sources impact visibility in Class I areas in other states.

The RH Rule requires a state to address RH in each Class I area outside the state which may be affected by emissions from within the state. The Mandatory Class I areas throughout the country are shown in Figure 2-1 on the following page. This document describes Indiana’s consultation process, technical analyses, and actions to be pursued to reduce visibility impairment in out-of-state Class I areas.

[illegible]

A reasonable progress analysis has been conducted for the electric generating units (EGUs) and four-factor analyses for the other non-EGU point sources selected. The reasonable progress analysis consists of a quantitative analysis of statewide NO_x and SO₂ emission reductions from Indiana's EGU fleet for 2009-2019; photochemical modeling using 2016 NO_x and SO₂ base-year modeled emissions for all existing Indiana EGUs in 2016 to project 2028 emissions; and source apportionment modeling to assess visibility impacts from all EGUs in Indiana. Two Portland cement manufacturing facilities met Indiana Department of Environmental Management's (IDEM's) source selection criteria for the RH SIP second implementation period four-factor analysis. IDEM evaluated the two Portland cement manufacturing facilities in terms of their cement kilns as a source category for the four-factor analysis. The owners/operators of the remaining seven sources that met the selection criteria for four-factor analysis were sent a request for information (RFI) requesting the companies submit a four-factor analysis for the

highest emitting NO_x and SO₂ emission units at each selected source. The emission units identified for NO_x and/or SO₂ four-factor evaluation were chosen based on the units' reported 2018 NO_x and SO₂ emissions. IDEM compared the emission units reported 2018 NO_x and SO₂ emissions to the units' NO_x and SO₂ 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 SO₂ emitters. No specific cutoff value or percentage was used to identify a facility's highest NO_x and SO₂ emitting units. Photochemical modeling using 2016 NO_x and SO₂ base-year modeled emissions for the cement kiln, iron and steel mills, and aluminum and plastics manufacturing sectors in 2016 to project 2028 emissions; and source apportionment modeling to assess visibility impacts from these sectors in Indiana.

3.0 REGIONAL PLANNING FOR REGIONAL HAZE

Regional planning for the 2021 RH SIP included LADCO, the six LADCO states and tribes located within the six states, the FLMs, and the EPA, Region 5.

3.1 Lake Michigan Air Directors Consortium - Regional Planning Organization

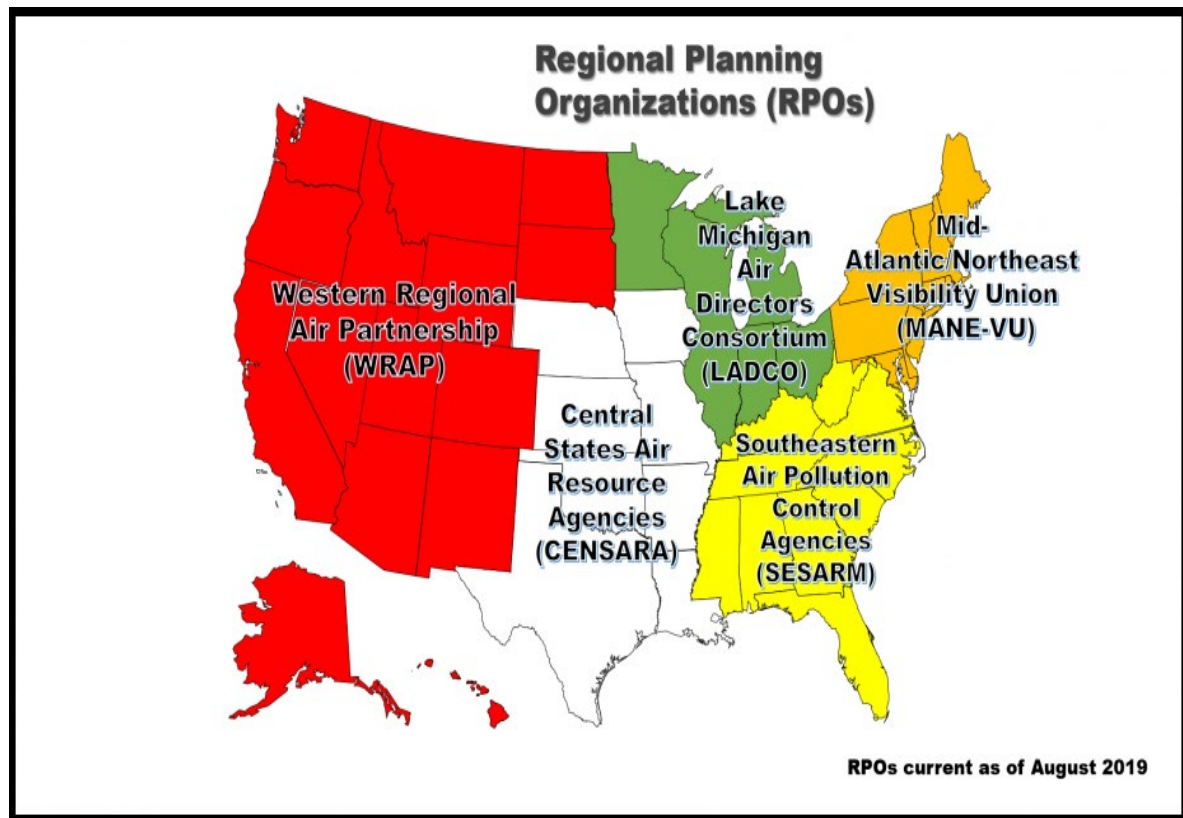
LADCO was designated as the RPO to receive federal grant funds on behalf of six Midwestern states. Member states include Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin. One of the primary objectives of LADCO is to assess both visibility impairment due to RH in the Class I areas located inside the borders of the six member states and assess the impact of emissions from the six states on visibility impairment due to RH in the Class I areas located outside the borders of the six states.

LADCO has defined its purposes of the organization as 1) Competency - Provide technically sound and defensible information to the LADCO state air programs, 2) Innovation - Work at the intersection of public health policy and air pollution science in ways that support innovation in how technical information is used to support public policy decisions, 3) Knowledge Building - Facilitate the transfer of technical skills and information to build capacity at state air agencies for fulfilling their missions, 4) Learning - Stay informed about emerging information on air pollution policy and science, 5) Open Communication - Exist as an organization that supports the free flow of ideas and information within LADCO and between LADCO and our member states, 6) Balance - Gain perspective on how the range of stakeholders in the region use technical information to understand the sources and controls of pollution.

3.2 Other Regional Planning Organizations

The other RPOs in the United States are Mid-Atlantic/Northeast Visibility Union (MANE-VU), Central Regional Air Planning Association (CENRAP) Southeastern Air Pollution Control Agencies (SESARM) and Visibility Improvement State and Tribal Association of the Southeast (VISTAS), and Western Regional Air Partnership (WRAP). Figure 3-1 on the next page shows a map of the regional planning organization boundaries and the states within each of the RPOs.

Figure 3-1 Regional Planning Organizations



Indiana does not have any Class I areas within its state borders. However, emissions from Indiana sources have been determined to impact Class I areas in other states. Sections 22 and 23 of this document contains a list of these Class I areas, and the analyses performed to assess the visibility impact from Indiana that were compiled by LADCO. It should be noted that Indiana does not impact any Class I areas within WRAP based on LADCO regional haze modeling and therefore Class I areas for this RPO will not be addressed. Results of this modeling are not detailed within this document but can be found in the LADCO's "Modeling and Analysis for Demonstrating Reasonable Progress for the Regional Haze Rule 2018-2028 Planning Period" Technical Support Document (TSD), dated June 17, 2021, and associated LADCO documentation, in Appendix L of this document.

The following Class I areas are listed as possibly being impacted by Indiana sources:

Southeastern U.S. (SESARM/VISTAS) - Sipsey National Wilderness Area, AL; Cohutta Wilderness Area, GA; Mammoth Cave National Park, KY; Great Smoky Mountains National Park, NC, and TN; Linville Gorge Wilderness Area, NC; James River Face National Wilderness Area, VA; Shenandoah National Park, VA; and Dolly Sods / Otter Creek National Wilderness Areas, WV

Eastern U.S. (MANE-VU) - Acadia National Park, ME; Moosehorn National Wilderness Area, ME; Great Gulf National Wilderness Area, NH; Brigantine National Wilderness Area, NJ; and Lye Brook National Wilderness Area, VT

Northern U.S. (LADCO) - Isle Royale National Park, MI; Seney National Wildlife Refuge, MI; Boundary Waters Canoe Area National Wilderness Area, MN; and Voyageurs National Park, MN

South Central U.S. (CENRAP) - Hercules-Glades National Wilderness Area, MO; Mingo National Wilderness Area, MO; Caney Creek National Wilderness Area, AR; and Upper Buffalo National Wilderness Area, AR

The Class I areas possibly being impacted by Indiana sources at the different RPOs throughout the eastern half of the country are shown in the Figures 3-2 through 3-4.

Figure 3-2 shows the locations of the Class I areas in northern U.S. (LADCO) - Isle Royale National Park, MI; Seney National Wildlife Refuge, MI; Boundary Waters Canoe Area National Wilderness Area, MN; and Voyageurs National Park, MN

Figure 3-2 Map Showing Locations of Class I Areas in Northern U.S.

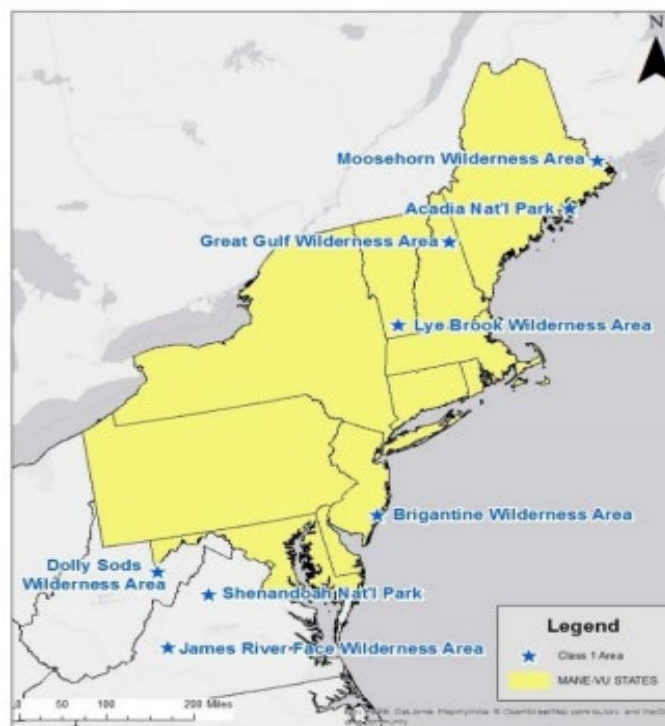
Figure 3-3 shows the locations of the Class I areas in southeastern U.S. (SESARM/VISTAS) - Sipsey National Wilderness Area, AL; Mammoth Cave National Park, KY; Great Smoky Mountains National Park and Joyce Kilmer Slickrock Wilderness Area, NC and TN; James River Face National Wilderness Area, VA; Shenandoah National Park, VA; and Dolly Sods/Otter Creek National Wilderness Areas, WV; Cohutta Wilderness Area, GA; Linville Gorge, NC; Swanquarter Wilderness Area, NC; Cape Romain Wilderness Area, SC; Okefenokee Wilderness Area, GA, Wolf Island Wilderness Area, GA; St. Mark's Wilderness Area, FL.

Figure 3-3 Map Showing Locations of South Central and Southeastern Class I Areas



Figure 3-4 shows the location of the Class I areas in northeastern U.S. (MANE-VU). Those Class I areas include Acadia National Park, ME; Moosehorn National Wilderness Area, ME; Great Gulf National Wilderness Area, NH; Brigantine National Wilderness Area, NJ; and Lye Brook National Wilderness Area, VT.

Figure 3-4 Map Showing Locations of Class I Areas in Northeastern U.S.



Central State Air Resources Agencies (CENSARA) states include Nebraska, Kansas, Oklahoma, Texas, Iowa, Missouri, Arkansas, and Louisiana. The Class I areas that are located in the southcentral U.S. (CENSARA/CenRAP) are Hercules-Glades National Wilderness Area, MO; Mingo National Wilderness Area, MO; Caney Creek National Wilderness Area, AR; and Upper Buffalo National Wilderness Area, AR.

Indiana's RH SIP utilizes data analyses, modeling results and other technical support documents prepared by LADCO. By coordinating with LADCO and other RPOs, Indiana has worked to ensure that its LTS provides sufficient emission reductions to mitigate visibility impacts of sources from Indiana on affected Class I areas. Class I areas outside the areas listed above were not analyzed further, as there was no impact from Indiana sources shown. Further, no impacts from Indiana were noted in the WRAP states and no requests for controls were initiated by those states. Therefore, Indiana focused its efforts on the surrounding Class I areas in the eastern RPOs.

3.3 Federal Land Managers Consultation

The provisions of 40 CFR 51.308(i) require coordination between Indiana and the FLMs. Opportunities have been provided by LADCO for FLMs to review and comment on each of the technical documents developed by LADCO and included in this SIP. Indiana has provided agency contacts to the FLMs as required. In development of this plan, the FLMs were consulted in accordance with subsection 40 CFR 51.308(i)(2).

During the consultation process, the FLMs were given the opportunity to address their:

- Assessment of the impairment of visibility in any Class I area.
- Recommendations on the development of reasonable progress goals.
- Recommendations on the development and implementation of strategies, including four-factor analyses, to address visibility impairment.

Indiana has consulted directly and indirectly with FLMs through emails, webinars, and conference calls, setup by LADCO for the RH SIP Second Planning Period workgroup meetings. FLM and U.S. EPA representatives were invited to participate in these meetings early in the SIP planning and development process. The consultation documentation related to these activities were captured by LADCO and stored on the organization's website for member states to reference and can be provided upon request.

Indiana also consulted directly with the FLMs through emails, and conference calls documented in Appendix K. The state consultation process was initiated on June 16, 2020 with a conference call with the FLMs to discuss IDEM's source selection process and selected sources for four-factor analysis and next steps in the SIP development process. The National Parks Service (NPS), LADCO, and IDEM Q/d rankings for four-factor analysis source selections can be found in the spreadsheets attached in Appendix N along with the United States Forest Service (FS) Q/d rankings list in Trent Wickman's October 2, 2020 email correspondence. Emissions for the LADCO and FS Q/d ranking lists were based on 2016 emissions, as described in LADCO's "Description of the Sources and Methods Used to Support Q/d Analysis for the 2nd Regional Haze Planning Period," dated October 14, 2020, 2014 NEI and 2017 CAMD emissions was used for the NPS Q/d ranking list, and 2016-2018 NEI and 2018 CAMD emissions were used for the IDEM Q/d ranking list. The 2016-2018 NEI emissions can be found in Appendix O and the 2018 CAMD data can be found in Appendix E. The final list of sources selected for four-factor analysis were based on IDEM's Q/d analysis with a cutoff of 5 using the most recent emissions data available for each source, which produced a similar list of sources among the four organizations' rankings.

Indiana provided the FLMs an opportunity for review of the draft RH SIP on May 18, 2021, at least 60 days prior to holding the public hearing for the SIP in accordance with 40 CFR 51.308(i)(2). IDEM conducted a virtual meeting with NPS on July 14, 2021 to discuss their comments and received NPS written comments and accompanying information on July 23, 2021. IDEM also received comments from the FS on August 6,

2021. Comments received from the FLMs on the draft RH SIP have been summarized and included along with IDEM's responses in Appendix U.

Indiana will continue to coordinate and consult with the FLMs in accordance with 40 CFR 51.308(i)(4) during the development of future progress reports and plan revisions, as well as during the implementation of programs having the potential to contribute to visibility impairment in the Class I areas. The FLMs will be consulted during the development and review of implementation plan revisions and during the review of five-year progress reports.

3.4 Letters Requesting Participation in Consultation Process from States with Class I Areas

As a result of the various analyses performed by the LADCO and other RPOs, Indiana was invited to participate in a number of consultations regarding its potential contributions to Class I areas. These include Arkansas, Missouri, and VISTAS. Copies of these letters are attached in Appendix A.

3.4.1 Arkansas Consultation

IDEM attended a virtual interstate consultation meeting with Arkansas to discuss RH planning on January 13, 2020. Then IDEM received consultation letters from the state on February 5, 2020, and March 1, 2021, as a result of CENSARA's photochemical modeling that identified two Indiana sources, Duke Energy's Gibson and AEP's Rockport power generating stations, as having visibility impacts on the Upper Buffalo Wilderness Area. The visibility impacts from these sources on Arkansas's Class I area were evaluated in Indiana's reasonable progress analysis in Section 8, modeling results in Section 23 and source apportionment modeling in Section 24 of this document.

3.4.2 Missouri Consultation

IDEM attended a virtual interstate consultation meeting with Missouri to discuss Indiana's plans for reasonable progress analysis under the RH rule on August 24, 2020. Missouri's consultation letter was received by Indiana on September 11, 2020. Photochemical modeling conducted by CenSARA identified two Indiana sources having visibility impacts on Mingo National Wildlife Refuge and the Hercules-Glades Wilderness area. Duke Energy's Gibson and AEP's Rockport power generating stations were identified in Missouri's consultation letter and their visibility impacts evaluated in Indiana's reasonable progress analysis in Section 8, modeling results in Section 23 and source apportionment modeling in Section 24 of this document.

3.4.3 VISTAS Consultation

IDEM received a consultation letter from VISTAS on June 22, 2020. Photochemical modeling conducted by the RPO identified three Indiana EGUs (AES's Petersburg, Duke Energy's Gibson and AEP's Rockport power generating stations) having visibility impacts on several Class I areas within the VISTAS region. Those Class I

areas include Sipsey Wilderness Area, Mammoth Cave National Park, Shining Rock Wilderness Area, Linville Gorge Wilderness Area, Great Smoky Mountains National Park, Cohutta Wilderness Area, Joyce Kilmer-Slickrock Wilderness Area and Otter Creek Wilderness Area. Since Duke Energy's Gibson, AEP's Rockport and AES's Petersburg power generating stations were identified in VISTAS' consultation letter, their visibility impacts and emissions were evaluated in Indiana's reasonable progress analysis in Section 8, modeling results in Section 23 and source apportionment modeling in Section 24 of this document. IDEM participated in the consultation process for these areas through VISTAS emails, webinars, and conference phone calls.

4.0 COMPOSITION OF REGIONAL HAZE

"Regional haze" is defined in 40 CFR 51.301 as "visibility impairment that is caused by the emission of air pollutants from numerous anthropogenic sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources." This visibility impairment is a result of anthropogenic emissions of particles and gases in the atmosphere that scatter and absorb (i.e., extinguish) light, thus acting to reduce overall visibility. The primary cause of RH is light extinction by particulate matter (PM). For purposes of the RH Rule, light extinction is estimated from measurements of PM and its chemical components (nitrate, sulfate, organic mass by carbon (OMC), light absorbing carbon (LAC), fine soil (FS), sea salt, and coarse material (CM)), assumptions about relative humidity at the monitoring site, and the use of a commonly accepted algorithm (Pitchford, et al., 2007). The direct and precursor pollutants that can impair visibility include sulfur dioxide (SO₂), nitrogen oxides (NO_x), fine and coarse PM, volatile organic compounds (VOC), and ammonia.

The most significant contributors to visibility impairment impacting Class I areas are NO_x, SO₂, and NH₄, the precursors to the formation of ammonium sulfate, ammonium nitrate and organic carbon. The emissions inventory and contribution assessment performed by LADCO for member states demonstrated that NO_x and SO₂ emissions were the key contributors to visibility impairment at Class I areas in the Northern Midwest region and the focus of Indiana's RH SIP technical analyses, and actions to be pursued to reduce visibility impairment in out-of-state Class I areas. These determinations were made through the work of the LADCO Regional Haze workgroup and Project Team/Technical Oversight Committee, as mentioned in Section 5.1 of LADCO's "Modeling and Analysis for Demonstrating Reasonable Progress for the Regional Haze Rule 2018-2028 Planning Period" Technical Support Document (TSD), dated June 17, 2021, attached in Appendix L.

As stated in 40 CFR 51.308(d)(1), baseline visibility conditions, progress goals and changes in visibility must be expressed in terms of deciviews (dv) units. The deciview is a unit of measurement of haze, implemented in a haze index (HI) that is derived from calculated light extinction. The design of the unit is so that uniform changes in haziness described by this index correspond approximately to uniform incremental changes in perception, across the entire range of conditions (i.e., from pristine to highly impaired). The HI is expressed in deciviews and are defined as the natural logarithm of the ratio of the extinction coefficient to Rayleigh scattering (Pitchford, et al., 2007).

$$\text{Deciview (b}_{\text{ext}}) = 10 \ln(b_{\text{ext}}/10)$$

Where the units of b_{ext} (total light extinction) and light scattering due to Rayleigh scattering (i.e., the “10” in the denominator of the logarithmic expression) are both expressed in inverse megameters (Mm^{-1}).

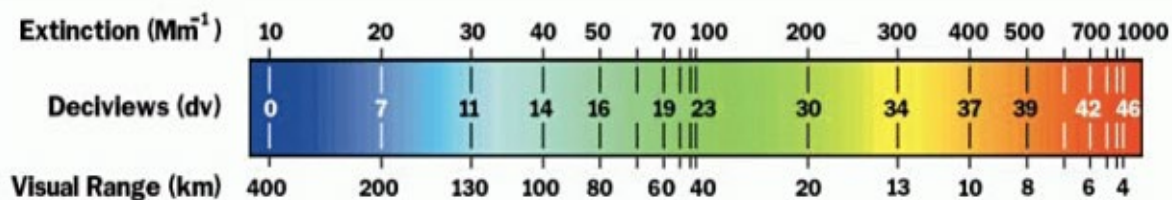
A change in deciviews, which is how progress in visibility is tracked, is given by the equation below. A one deciview change is equivalent to ~10% change in b_{ext} .

$$\Delta dv = dv_{\text{future}} - dv_{\text{base}}$$

A negative number indicates a reduction in deciviews, which is an improvement in visibility.¹

EPA’s “Technical Support Document (TSD) Revised Recommendations for Visibility Progress Tracking Metrics for the Regional Haze Program” dated July 2016 provided guidance on the baseline visibility conditions, progress goals and changes in visibility. Figure 4-1 graphically shows the relationship between deciviews, light extinction and visual range, which is a third metric used to describe visibility conditions.

Figure 4-1 Relationship between Deciviews, Light Extinction, and Visual Range



5.0 ASSESSMENT OF BASELINE CONDITIONS AND ESTIMATE OF NATURAL CONDITIONS IN CLASS I AREAS

The RH Rule requires states with Class I areas to establish RPGs for visibility improvement at each affected Class I area. The goals must provide for reasonable progress toward achieving natural visibility conditions, provide for improvement in visibility for the most impaired days over the period of the implementation plan, and ensure no degradation in visibility for the least impaired days over the same period, 40 CFR 51.308(d)(1). While Indiana does not have any Class I areas within its borders, emissions from the state can potentially impact visibility at surrounding Class I areas so assessment of baseline and natural conditions at those Class I areas is critical to estimating Indiana’s visibility impacts.

Section 51.308(f)(2) of the RH Rule requires each state to develop a LTS 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.” Also, section 51.308(f)(3) of the Rule

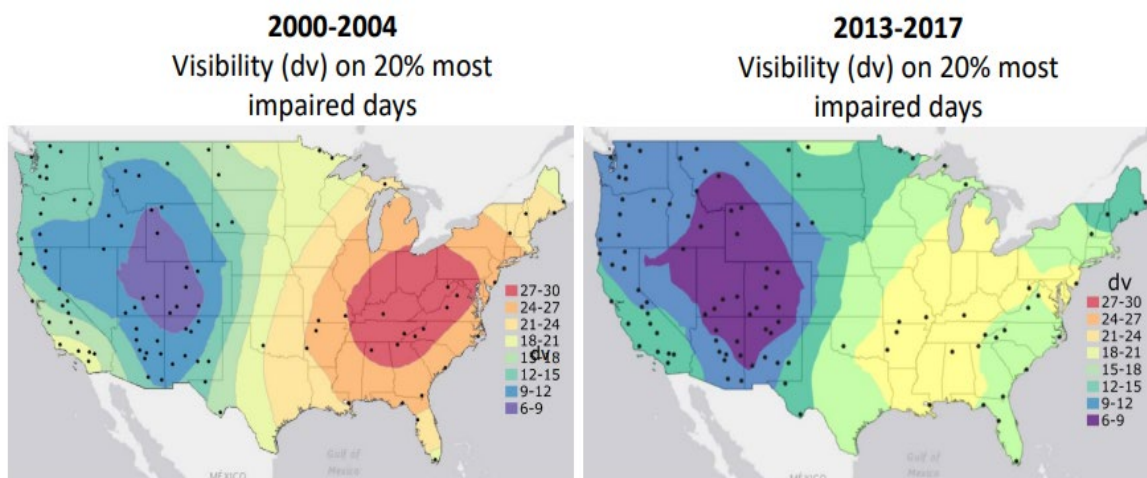
¹ EPA’s Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM_{2.5} and Regional Haze, EPA 454/R-18-009, November 2018

provides that if a state contains sources whose emissions are reasonably anticipated to contribute to visibility impairment in a Class I area in another state for which the RPG is above the URP glidepath, the state must provide a “robust demonstration” that there are no additional emission reduction measures that would be reasonable to include in its own LTS. No robust demonstrations were necessary as the modeled RPGs at Class I areas were below their respective URP.

5.1 Visibility Progress Based on IMPROVE Ambient Data

The EPA Office of Air Quality Planning and Standards (OAQPS), in a September 10, 2019 presentation, provided an update on the progress of visibility throughout the country from 2000 through 2017, based on the Interagency Monitoring of Protected Visual Environments (IMPROVE) ambient monitoring data. As can be seen below in Figure 5-1, the visibility in terms of deciviews has improved greatly, especially in the eastern half of the country. OAQPS stated that according to the U.S. National Park Service, as of 2014, emission controls established under the first implementation period of the RH Rule led to approximately 500,000 tons per year of SO₂ and 300,000 tons per year of NO_x reductions. These emission reductions equated to significant visibility improvements on the order of 6 to 12 deciviews in the eastern half of the country and average visual range increasing by 20 to 30 miles in Class I areas.

Figure 5-1 Comparison of Visibility on 20% Most Impaired Days 2000-2017



The IMPROVE monitored visibility values for the period of 2014 through 2018 are below the base-year 2016 and future year 2028 modeled visibility results in most instances. This indicates that visibility improvements already realized are well ahead of the glidepaths of all Class I areas, especially those in the eastern half of the country that Indiana may impact.

5.2 Regional Haze/Visibility Determination

Regional haze is measured by an extinction coefficient (b_{ext}) that represents light attenuation resulting from scattering and absorption of light from ambient PM plus

scattering of light due to gas molecules in the air (i.e., Rayleigh scattering). Although b_{ext} can be estimated by several different methodologies, the RH Rule requires that it be estimated using measured ambient PM. This follows since, for a given set of meteorological conditions, visibility can be improved by reducing concentrations of ambient PM. Thus, deriving b_{ext} in this manner provides a direct link between RH and related pollutant concentrations.

The components of the visibility equation match up very closely to the prominent chemical forms of $\text{PM}_{2.5}$: nitrate ion, sulfate ion, ammonium ion, organic carbon, elemental carbon, and soil (EPA, 2007). Since these modeling applications will support $\text{PM}_{2.5}$ /Haze rules, model performance will be most rigorous for each of these $\text{PM}_{2.5}$ species and coarse mass.

Organic material is typically estimated from organic carbon using a factor of 1.4, which is based on the assumption that carbon accounts for 70% of the organic mass. Recent literature recommends a factor of 1.6 ± 0.2 for urban aerosol and 2.1 ± 0.2 for non-urban areas that see more aged aerosols (Turpin and Lim, 2001; IMPROVE, 2006). These factors are applied to observation data based on land use type before being compared to model output. These factors may also be used to reduce modeled estimates of organic material to organic carbon.

Section 51.308(f)(1) of the RH Rule requires each state with a Class I area to calculate the baseline, current, and natural visibility conditions as well as to determine the visibility progress to date and the URP. EPA recommends using the IMPROVE network ambient data to identify the 20% most anthropogenically impaired days and the 20% clearest days.

EPA's "Technical Support Document (TSD) Revised Recommendations for Visibility Progress Tracking Metrics for the Regional Haze Program" provided guidance on the 20% most anthropogenically impaired days which represent those days with the highest anthropogenic visibility impairment in deciviews. This is determined by subtracting the natural portion of the deciview value from the total deciview value for the day:

$$\Delta \text{dv}_{\text{anthropogenic visibility impairment}} = \text{dv}_{\text{total}} - \text{dv}_{\text{natural}}$$

where dv_{total} is the overall deciview value for a day and $\text{dv}_{\text{natural}}$ is the natural portion of the deciview value for a day.

A natural deciview is calculated by assigning daily extinction values into three categories: 1) episodic natural, 2) routine nature, and 3) anthropogenic. Episodic natural is typically associated with extreme events such as wildfire smoke and dust storms identified by a site-specific threshold of carbon (organic and elemental) and dust (fine soil and coarse matter) based on observed IMPROVE 95th percentile values from 2000-2014. Non-episodic extinction values for each day are associated with routine natural and anthropogenic categories based on the ratio of the Natural Conditions II estimates and non-episodic annual average, update to the EPA's original 2006 natural conditions estimates, for each chemical species. Any remaining extinction after determining the episodic and routine natural extinction is assigned to the anthropogenic category.

Days selected as the 20% most anthropogenically impaired have the highest anthropogenic extinction relative to the natural extinction. The natural visibility conditions are calculated by the average of the 2000-2014 annual averages of the natural portion of the deciview value for a day from the 20% most anthropogenically impaired days.

The URP is calculated according to the follow equation:

$$\text{URP} = [(\text{2000-2004 visibility})_{20\% \text{ most impaired}} - (\text{natural visibility})_{20\% \text{ most impaired}}]/60$$

2000-2004 represents the baseline period of the URP and 2064 represents the endpoint where the deciview value of the URP is assumed for the purpose of analysis to reach natural visibility conditions.

20% clearest days are those days with the lowest daily extinction and deciview values, not the days with the lowest anthropogenic impairment. It is unnecessary to assign extinction on the clearest days to anthropogenic and natural fractions.

Performance metrics used to describe model performance for PM_{2.5} species include mean bias, gross error, fractional bias, and fractional error (EPA, 2007). The bias and error metrics are used to describe performance in terms of the measured concentration units (µg/m³). Even though the distribution of PM_{2.5} is log-normal, the data is not transformed for this analysis. The model attainment tests outlined by EPA for the PM_{2.5} National Ambient Air Quality Standards (NAAQS) and RH Rule require relative response factors to be applied to actual concentrations and not transformed concentrations. No minimum value is used to eliminate data points for the purposes of this analysis.

5.3 IMPROVE Algorithm to Calculate Regional Haze Visibility

The IMPROVE equation or algorithm reflects empirical relationships derived between measured mass of PM components and transmissometer measurements of b_{ext} at a subset of monitoring sites in Class I areas within the IMPROVE monitoring network. The IMPROVE program revised the IMPROVE algorithm in 2006 (Hand, 2006); (Pitchford, 2007). The revised algorithm, as stated in Colorado State University's "Revised IMPROVE Algorithm for Estimating Light Extinction from Particle Speciation Data," is intended to reduce biases in light extinction estimates.

The revised algorithm is as follows:

$$b_{\text{ext}} = 2.2 \times f_s(\text{RH}) \times (\text{Small Ammonium Sulfate}) + 4.8 \times f_L(\text{RH}) \times (\text{Large Ammonium Sulfate}) + 2.4 \times f_s(\text{RH}) \times (\text{Small Ammonium Nitrate}) + 5.1 \times f_L(\text{RH}) \times (\text{Large Ammonium Nitrate}) + 2.8 \times (\text{Small Organic Mass}) + 6.1 \times (\text{Large Organic Mass}) + 10 \times (\text{Elemental Carbon}) + 1 \times (\text{Fine Soil}) + 1.7 \times f_{ss}(\text{RH}) \times (\text{Sea Salt Mass}) + 0.6 \times (\text{Coarse Mass}) + \text{Rayleigh Scattering (site specific)} + 0.33 \times (\text{Mm}^{-1}/\text{ppb}) \times [\text{NO}_2 \text{ (ppb)}]$$

The numerical coefficients on the right-hand side of the equation represent the light scattering or absorption efficiency, m^2/gm of the corresponding component of PM,

- $f_s(\text{rh})$, $f_L(\text{rh})$, $f_{ss}(\text{rh})$ are relative humidity adjustment factors applied to the light scattering efficiency (to be described in greater detail shortly), dimensionless;
- SO_4 is the mass associated with sulfates, $\mu\text{g}/\text{m}^3$;
- NO_3 is the mass associated with nitrates, $\mu\text{g}/\text{m}^3$;
- OC is the mass associated with organic carbon, $\mu\text{g}/\text{m}^3$;
- EC is the mass associated with elemental carbon, $\mu\text{g}/\text{m}^3$;
- Fine Soil is inorganic primary particulate matter (excluding primary sulfate and nitrate particles) associated with soil components with aerodynamic diameter $< 2.5 \mu\text{m}$, $\mu\text{g}/\text{m}^3$;
- CM is coarse PM with aerodynamic diameter $> 2.5 \mu\text{m}$, but $< 10 \mu\text{m}$, $\mu\text{g}/\text{m}^3$;
- brayleigh is light-scattering attributable to Rayleigh scattering, Mm^{-1} (i.e., inverse “mega-meters”); and b_{ext} is the estimated extinction coefficient, Mm^{-1} .

The total sulfate, nitrate, and organic mass concentrations are each split into two fractions, representing small and large size distributions of those components. The organic mass concentration is calculated as 1.8 times the measured IMPROVE organic carbon concentration, to adjust for organic mass from elements other than carbon. Terms are included for sea salt (important for coastal locations) and for absorption by NO_2 (only used where NO_2 data are available). Site-specific Rayleigh scattering is calculated based on the elevation and annual average temperature of each IMPROVE monitoring site.

The apportionment of the total concentration of sulfate compounds into the concentrations of the small and large size fractions is accomplished using the following equations:

$$\begin{aligned}\text{Large Sulfate} &= \text{Total Sulfate}/20 \mu\text{g}/\text{m}^3 \times \text{Total Sulfate, for Total Sulfate} < 20 \mu\text{g}/\text{m}^3 \\ \text{Large Sulfate} &= \text{Total Sulfate, for Total Sulfate} \geq 20 \mu\text{g}/\text{m}^3 \\ \text{Small Sulfate} &= \text{Total Sulfate} - \text{Large Sulfate}\end{aligned}$$

The same equations are used to apportion total nitrate and total organic mass concentrations into the small and large size fractions.

Sea salt is calculated as $1.8 \times (\text{Chloride})$ or $1.8 \times (\text{Chlorine})$ if the chloride measurement is below detection limits, missing or invalid. The algorithm also uses three water growth adjustment terms. They are for use with the small size distribution and the large size distribution sulfate and nitrate compounds and for sea salt [$f_s(\text{RH})$, $f_L(\text{RH})$ and $f_{ss}(\text{RH})$ respectively].

As stated in 40 CFR 51.308(d)(1), baseline visibility conditions, progress goals and changes in visibility must be expressed in terms of deciview (dv) units. The deciview is a unit of measurement of haze, implemented in a haze index (HI) that is derived from calculated light extinction. The design of the unit is so that uniform changes in haziness described by this index correspond approximately to uniform incremental changes in perception, across the entire range of conditions (i.e., from pristine to highly impaired).

The HI is expressed in deciviews and is defined as the natural logarithm of the ratio of the extinction coefficient to Rayleigh scattering (Pitchford, et al., 2007).

$$\text{Deciview } (b_{\text{ext}}) = 10 \ln(b_{\text{ext}}/10)$$

Where the units of b_{ext} (total light extinction) and light scattering due to Rayleigh scattering (i.e., the "10" in the denominator of the logarithmic expression) are both expressed in Mm^{-1} .

All or nearly all states used the IMPROVE algorithm in their SIPs for the first implementation period and the IMPROVE program has stopped reporting visibility data using the original 148 IMPROVE equation. Therefore, EPA now recommends using the revised IMPROVE equation for all reasonable progress related modeling calculations.

5.4 Speciation Analysis

Plots of light extinction by particulate species for 2016 are available from the IMPROVE website. For the 13 selected Class I areas, ammonium sulfate is the dominate species at 11 areas, contributing 50% or more to light extinction. See Appendix B for Class I area speciation plots. The two areas where this is not the case are Mingo and Seney, where ammonium nitrate contributes 32% and 43%, respectively to light extinction. Ammonium sulfate is still the dominate species contributing to light extinction at Mingo. However, ammonium nitrate is the dominate species at Seney, where ammonium sulfate contributes 32%. Therefore, Indiana believes a continued focus on sulfate reduction will help to bring the Class I areas back towards natural visibility conditions.

5.5 Glidepaths to Natural Conditions in 2064

The states and RPOs with Class I areas performed their analyses to determine baseline conditions and natural conditions in 2064. The RH Rule directs states to graphically show what would be a "uniform rate of progress" toward natural conditions for each Class I area within their state as well as Class I areas outside the state which may be affected by emissions from sources within the state. The uniform rate of progress is also known as the "glidepath." The glidepath is a straight line drawn from the baseline level of visibility impairment for 2000 - 2004 to the level representing no anthropogenic impairment by 2064.

Glidepaths were developed by the states and RPOs for their own Class I areas using their available information. LADCO also developed glidepaths for the Class I areas impacted by states within the RPO. The glidepath is one of the indicators used in setting reasonable progress goals. The 2016 base-year glidepath indicate 2028 projections will remain well below the URP for all Class I areas that Indiana has significant visibility impacts. These glidepaths for Class I areas that Indiana has visibility impacts are located in Section 23 of this document.

5.6 Emissions Inventory

A great deal of technical information must be assembled to determine the causes of anthropogenically impaired visibility in the Class I areas. 40 CFR 51.308(d)(4)(v) requires a statewide emission inventory of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any mandatory Class I area. Photochemical modeling is used to determine the visibility impacts and requires detailed emissions inventories containing temporally allocated (i.e., hourly) emissions for each grid-cell in the modeling domain for a large number of chemical species that act as primary pollutants and precursors to secondary pollutants. The pollutants inventoried by Indiana for this photochemical modeling include NO_x, SO₂, VOCs, PM_{2.5}, and PM₁₀ as collected through Indiana's emissions reporting rules. Ammonia emissions are not reported to the state and are therefore represented by model estimates of ammonia provided by LADCO.

In addition, 40 CFR 51.308(f)(2)(iii) states "The state must document the technical basis, including modeling, monitoring, cost, engineering, and emissions information, on which the state is relying to determine the emission reduction measures that are necessary to make reasonable progress in each Class I area it affects. The emissions information must include, but need not be limited to, information on emissions in a year at least as recent as the most recent year for which the state has submitted emission inventory information to the Administrator in compliance with the triennial reporting requirements of subpart A of this part. However, if a state has made a submission for a new inventory year to meet the requirements of subpart A in the period 12 months prior to submission of the SIP, the state may use the inventory year of its prior submission." An inventory was developed for the baseline year 2016. In addition, projections of future emissions have been made for 2028. Indiana will update this inventory on a periodic basis, every three years.

5.7 Base Year Emissions

Through coordination with LADCO and other states, a base year inventory for 2011 and 2016 was prepared for regional modeling analysis. IDEM and the other LADCO states reviewed methodologies and assisted in the preparation of key segments of the emissions inventory that was eventually submitted to LADCO. Both platforms were developed and used for EPA RH modeling efforts. Further justification for selection of the modeling base years can be found in Section 3.1 Air Quality Modeling - Modeling Years Justification of LADCO's "Modeling and Analysis for Demonstrating Reasonable Progress for the Regional Haze Rule 2018-2028 Planning Period" Technical Support Document (TSD), dated June 2021.

For on-road, nonroad, ammonia, and biogenic sources, the 2016 emissions were estimated by models. For the other sectors, point sources, area sources, and MAR (commercial marine, aircraft, and railroads), the 2016 emissions were prepared using data supplied by the LADCO states and, for non-LADCO states, data developed by other RPOs.

The 2016 emissions data for this study were based on the EPA 2016 v1 (“2016fh_16”) emissions modeling platform (<http://views.cira.colostate.edu/wiki/wiki/10202>). EPA and the 2016 Collaborative generated this platform for use for ozone modeling and the development of the RH SIP. Twelve different workgroups collaborated to construct 2016 base-year emissions and future year emissions estimates. The first version of the 2016 inventories used 2014 inventory data. Later versions of the inventory fully integrated 2016 estimates of emissions activities, growth and controls, and the latest emissions factors. The 2016v1 emissions modeling platform includes point sources, nonpoint sources, commercial marine vessels (CMV), on-road and nonroad mobile sources, and fires for the U.S., Canada, and Mexico. Descriptions of all the emission sectors that were factored into the modeling are given in [2016v1_EmisMod_TSD \(epa.gov\)](#).

Table 5-1 lists the 2016 base year inventory components that LADCO used to simulate 2016 air quality for this application.

Table 5-1 LADCO 2016 Emissions Modeling Platform Inventory Components

Sector	Abbreviation	Data Source	Future Year Data Source
Agriculture	ag	EPA 2016fh	U.S. EPA 2028f
Fugitive Dust	afdust	U.S. EPA 2016fh	U.S. EPA 2028fh
Airports	airports	EPA 2016fh	LADCO2028v1b
Biogenic	beis	EPA 2016fh	U.S. EPA 2016fh
C1/C2 Commercial Marine	cmv_c1c2	EPA 2016fh	U.S. EPA 2028fh
C3 Commercial Marine	cmv_c2	EPA 2016fh	U.S. EPA 2028fh
Nonpoint	nonpt	EPA 2016fh	U.S. EPA 2028fh
Off-road Mobile	nonroad	EPA 2016fh	U.S. EPA 2028fh
Nonpoint Oil & Gas	np_oilgas	EPA 2016fh	U.S. EPA 2028fh
On-road Mobile	on-road	EPA 2016fh	U.S. EPA 2028fh
Point Oil & Gas	pt_oilgas	EPA 2016fh	U.S. EPA 2028fh
Agricultural Fires	ptagfire	EPA 2016fh	U.S. EPA 2016fh
Electricity Generation	ptertac	ERTAC 16.1	ERTAC 16.1
Wild and Prescribed Fires	ptfire	EPA 2016fh	U.S. EPA 2016fh
Industrial Point	ptnonertac	EPA 2016fh	MARAMA 16.1 2028
Minnesota Taconite	ptmntaconite	Provided by MPCA	Provided by MPCA
Rail	rail	EPA 2016fh	U.S. EPA 2028fh
Residential Wood Combustion	rwc	EPA 2016fh	U.S. EPA 2028fh
Mexico Anthropogenic	othar/othpt/	EPA 2016fh	U.S. EPA 2028fh
Canada Anthropogenic	othar/othpt	EPA 2016fh	U.S. EPA 2028fh

Several emission sectors use day specific temperature and activity as the basis of their emissions. Since different years have different meteorology and activity, the base and

future year emissions depend on the base year conditions. These sectors include biogenics, wind-blown dust, wildfire, prescribed fire, and motor vehicles.

5.8 On-road Mobile

LADCO staff worked with the Coordinating Research Council to build national emissions modeling inputs that became the county specific national defaults for on-road mobile sources that resulted in improved emissions in the 2016 modeling platform. This includes projects that decoded all the vehicle identification numbers in the country for updated age distributions, Telemetry data for vehicle speed and a second Telemetry project for data on time of day/month/year activity.

Motor Vehicle Emissions Simulator (MOVES) was run using transportation data e.g., vehicle miles traveled (VMT) and vehicle speeds] supplied by the state and local planning agencies in the LADCO states. 2016 on-road mobile source gasoline and diesel vehicles from moving and non-moving vehicles that drive on roads, along with vehicle refueling. Includes the following modes: exhaust, extended idle, auxiliary power units, evaporative, permeation, refueling, and brake and tire wear.

All states, except California, developed mobile emissions using winter and summer MOVES2014b emissions tables coupled with activity data projected to year 2016 or provided by State/Local/Tribal agencies. Sparse Matrix Operator Kernel Emissions (SMOKE)-MOVES was used to compute emissions from the emission factors and activity data.

5.9 Nonroad Mobile

2016 nonroad equipment emissions were developed with the MOVES2014b model which incorporated updated equipment growth rates. MOVES was used for all states within the LADCO region, including Indiana.

5.10 Area Sources

Industrial Adhesives and Sealants: The National Emissions Inventory (NEI) shows this to be a large VOC emissions category in the LADCO states. The Industrial Adhesives and Sealants category (SCC 2440020000) and the Consumer and Commercial Adhesives and Sealants nonpoint category (SCC 2460600000 - all adhesives and sealants) are among the VOC emission sectors that were included. A ratio of 2016 population to 2014 population was used to create a growth factor that was applied to the 2014NEIv2 emissions with SCCs matching the population-based SCCs.

Outdoor Wood Boilers: were established from emissions taken from the NEI2014v2 to project to 2016 by projection factors derived by MARAMA based on implementing the projection methodology from EPA's 2011 platform. These projection factors are by Standard Classification Code (SCC) and SCC pollutant.

PM₁₀ and PM_{2.5} fugitive dust sources from the 2014NEIv2 nonpoint inventory with paved road dust grown to 2016 levels; including building construction, road construction, agricultural dust, and road dust. The NEI emissions are reduced during modeling according to a transport fraction (newly computed for the 2016 beta platform) and a meteorology-based (precipitation and snow/ice cover) zero-out. Afdust emissions from the portion of Southeast Alaska inside the 36US3 domain are processed in a separate sector called 'afdust_ak'. Geographic and temporal profiles were based on county and monthly resolution.

5.11 Point Sources - EGUs and non-EGUs

LADCO replaced the Integrated Planning Model (IPM) EGU inventories in the EPA 2011 and 2016 modeling platforms with inventories derived from the Eastern Regional Technical Advisory Committee (ERTAC) EGU model (MARAMA, 2012). The ERTAC EGU model for growth was developed around activity pattern matching algorithms designed to provide hourly EGU emissions data for air quality planning.

The ERTAC EGU model imports base year Continuous Emissions Monitoring (CEM) data from EPA and sorts the data from the peak to the lowest generation hour. It applies hour specific growth rates that include peak and off-peak rates. The model then balances the system for all units and hours that exceed physical or regulatory limits. ERTAC EGU applies future year controls to the emissions estimates and tests for reserve capacity, generates quality assurance reports, and converts the outputs to SMOKE-ready modeling files.

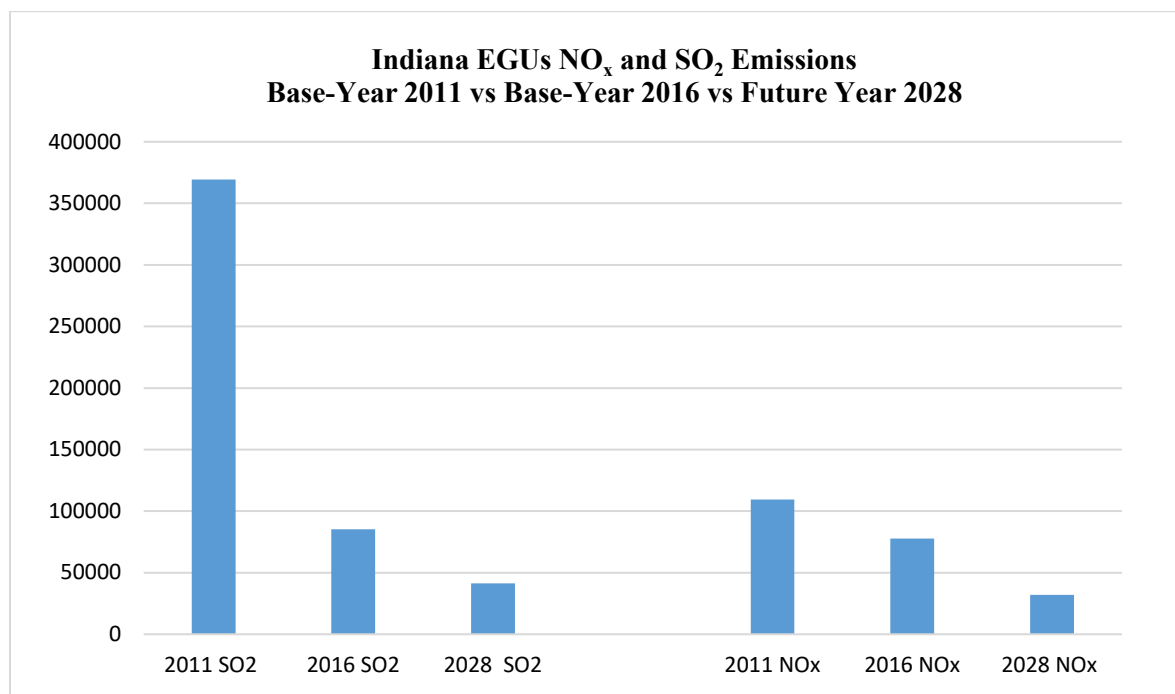
ERTAC EGU generates hourly future year emissions estimates. The model does not shutdown or mothball existing units because economic algorithms suggest they are not economically viable. Additionally, alternate control scenarios are easy to simulate with the model. Significant effort has been put into the model to prevent simulations from spawning new coal plants to meet forecasted power demand. As an alternative, the model now allows portability of generation to different fuels like renewables and natural gas (NG).

ERTAC EGU 16.1 integrated state-reported information on EGU operations and forecasts as of December 2019. LADCO considers that the ERTAC EGU Tool provides more accurate estimates of the growth and control forecasts for EGUs in the Midwest and Northeast states than the approach used in EPA's "2016fh" modeling platform. There is a corresponding non-EGU point inventory sector developed by ERTAC that ensures consistency with the EGU sector. LADCO used the ERTAC non-EGU point inventory in our 2016 modeling platform. Future year emissions were based on LADCO's ERTAC Continental US v16.1 emissions modeling.

Graph 5-1 summarizes the SO₂ and NO_x emissions for EGUs throughout Indiana for base-years 2011 and 2016 and projected emissions for 2028. A list of the Indiana EGUs NO_x and SO₂ emissions used to generate Graph 5-1 can be found in the tables in Appendix E by facility and unit. The net effect is decreases in SO₂ and NO_x emissions statewide. SO₂

emissions dropped dramatically from 2011 to 2016 with reductions equating to 76.9%. NO_x emissions were reduced by 29% from 2011 to 2016. As can be seen, projected SO₂ and NO_x emissions for Indiana EGUs in 2028 decrease even more with SO₂ emission dropping an additional 51.5% from 2016 to 2028 and NO_x emissions reduced by 58.8%. In total, from 2011 to 2028, Indiana EGU SO₂ and NO_x emissions are projected to decrease by 88.8% for SO₂ and 70.8% for NO_x.

Graph 5-1 Indiana Electric Generating Units NO_x and SO₂ Emissions - Base Year 2011 vs Base Year 2016 vs Future Year 2028



The reduction in base-year emissions from 2011 to 2016 is rather significant when evaluated with the improvement in visibility at Class I areas, as discussed in Section 23 of this document. These actual emission reductions have brought monitored visibility values well below the glidepath for each Class I area. In fact, the monitored visibility improvement for the period of 2014 through 2018 are nearly equal to the modeled visibility results for base-year 2016 - future year 2028 and in most cases, are below the base-year 2011 - future year 2028 modeled visibility results. This points to the fact that visibility improvements already realized are well ahead of the glidepaths of all Class I areas in the eastern half of the country where Indiana may have visibility impacts.

The reduction in NO_x and SO₂ emissions can be attributed in part to several federal regulations and the 1-hour SO₂ standard instituted in 2011 that have helped to reduce SO₂ substantially in the past decade. Among the biggest sources of SO₂ emissions are coal-fired boilers and with many planned retirements of boilers at several utilities throughout the state, future emission reductions are expected. The expected retirements at many of those power plants Indiana by 2028 are listed in Section 8, Tables 8-5 and 8-6.

To address retirements of EGUs, LADCO modified the ERTAC EGU 16.1 inventory forecasts for 2028 to exclude the emissions from 62 EGU units in the LADCO region that announced shutdowns that will occur before 2028. These announcements came after the ERTAC EGU 16.1 emissions were developed and did not include any additional Indiana units. Therefore, LADCO zeroed out the 2028 emissions from some units in the 2016-based modeling forecasts for 2028. All Indiana EGUs were accounted for in the original 16.1 inventory used for the 2016 modeling and could be verified through the ERTAC EGU emission files used in the modeling exercise and can be provided by LADCO.

5.12 Other Emissions Processing Improvements

Canadian and Mexican Emissions: Point sources from the Environment and Climate Change Canada (ECCC) 2015 emission inventory, including agricultural ammonia, along with emissions from Mexico's 2008 inventory projected to 2014 and 2018 and then interpolated to 2016. Agricultural data were originally provided on a rotated 10-km grid for beta but were smoothed so as to avoid the artifact of grid lines in the processed emissions. Monthly resolution for Canada agricultural and airport emissions, annual resolution for the remainder of Canada and all of Mexico.

Biogenic Emissions: Year 2016, hour-specific, grid cell-specific emissions generated from the Biogenic Emissions Inventory System version 3.61 (BEIS3.61) model within SMOKE, including emissions in Canada and Mexico using Biogenic Emissions Land use Database version 4.1 (BELD v4.1) "water fix" land use data (including improved treatment of water grid cells).

Ammonia Emissions: Nonpoint livestock and fertilizer application emissions. Livestock includes ammonia and other pollutants (except PM_{2.5}) and was backcasted from a draft version of 2017 NEI based on animal population data from the U.S. Department of Agriculture (USDA) National Agriculture Statistics Service Quick Stats, where available. Fertilizer includes only ammonia and is estimated for 2016 using the Fertilizer Emission Scenario Tool (FEST) for Community Multiscale Air Quality (CMAQ) otherwise known as FEST-C model. Geographic and temporal profiles were based on county and monthly resolution.

The Canadian and Mexican emissions were taken from Section 2.7.1 of U.S. EPA's "Technical Support Document (TSD) Preparation of Emissions Inventories for 2016v1 Norther American Emissions Modeling Platform" (September 2020) while the biogenics and ammonia information was taken from Table 2.1 "Platform Sectors for the 2016 emissions modeling case" of the same U.S. EPA TSD.

5.13 Emissions Summaries

LADCO based the 2016 and 2028 emissions data for this study on the EPA 2016fh_16 ("FH") emissions modeling platform (US EPA, 2020). LADCO replaced the EGU emissions in the EPA FH platform with 2028 EGU forecasts estimated with a modified version of the ERTAC EGU Tool version 16.1 (MARAMA, 2012). The total emissions

modeled by LADCO are included in Table 5-2, showing the base-year emissions from 2016.

Table 5-2 Indiana’s 2016 Base-Year Modeled Emissions

Emission Group	2016 Emissions (tons/year)				
	NH ₃	NO _x	PM _{2.5}	SO ₂	VOC
Biogenics	---	21,381	---	----	279,976
Fires	720	697	3,849	359	10,356
NonPoint	81,708	34,816	46,889	1,142	129,207
Nonroad	56	36,791	3,208	66	20,407
On-road	2,737	103,694	3,385	616	55,049
Point	1,504	129,763	26,010	127,145	33,222

Figure 5-2 and Figure 5-3 are tile plots of the 12-km gridded, daily total NO_x and SO₂ emissions, respectively, for a summer weekday in 2016 for U.S., Canadian and Mexican sources within the modeling domain. Figure 5-4 shows the NH₃ daily total emissions for the summer weekday and Figure 5-5 shows the tile plot of PM_{2.5} daily total emissions. The NO_x plot illustrates that the highest emissions occur in proximity urban areas and roadways. The SO₂ plot shows that coal EGU point sources and urban areas are the dominant emission sources for this pollutant. Table 5-6 shows the 2016 annual emissions totals by LADCO member state and major inventory group. For further details of the modeled emissions, please refer to Section 4.2 of LADCO’s RH TSD, June 17, 2021 attached in Appendix L.

Figure 5-2 12-Kilometer Gridded Daily Total NO_x Emissions for Summer Weekday

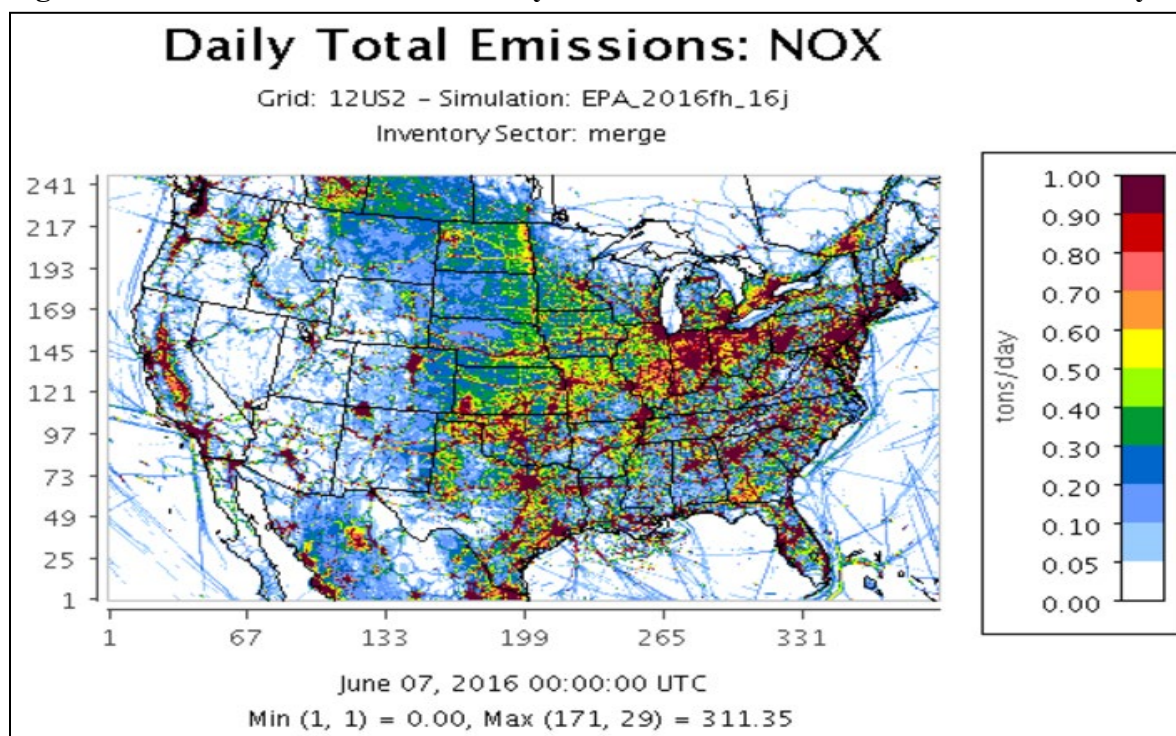


Figure 5-3 12-Kilometer Gridded Daily Total SO₂ Emissions for Summer Weekday

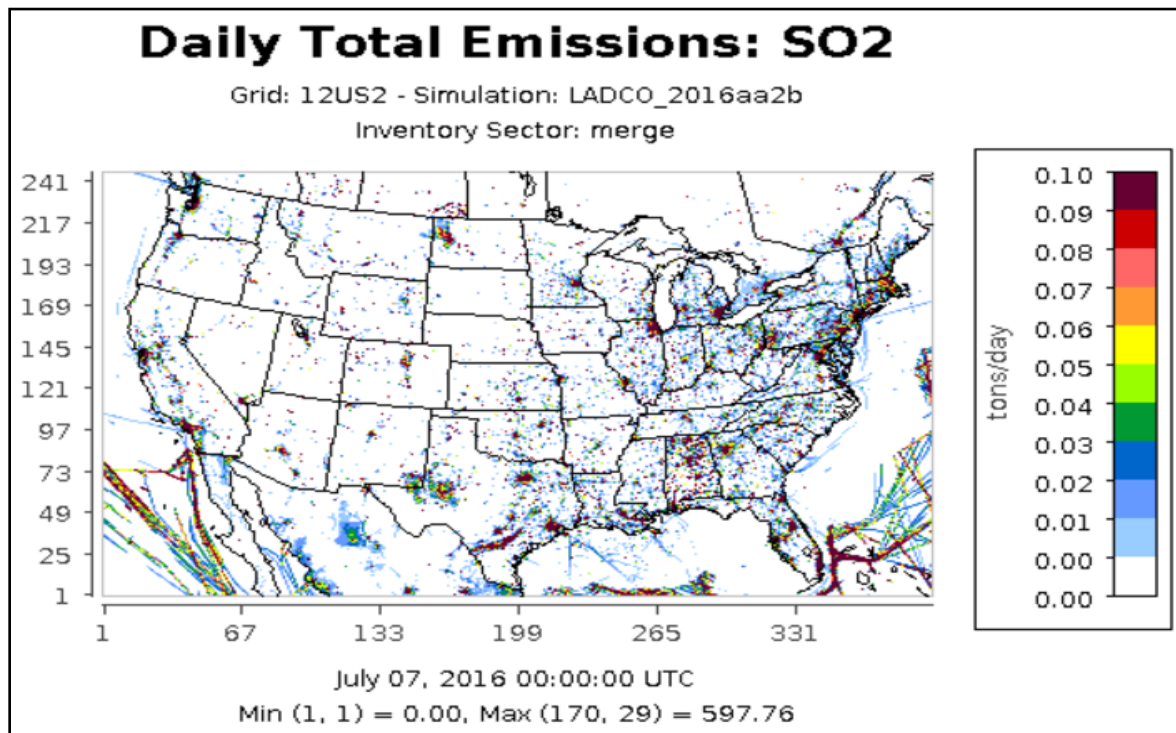


Figure 5-4 12-Kilometer Gridded Daily Total NH₃ Emissions for Summer Weekday

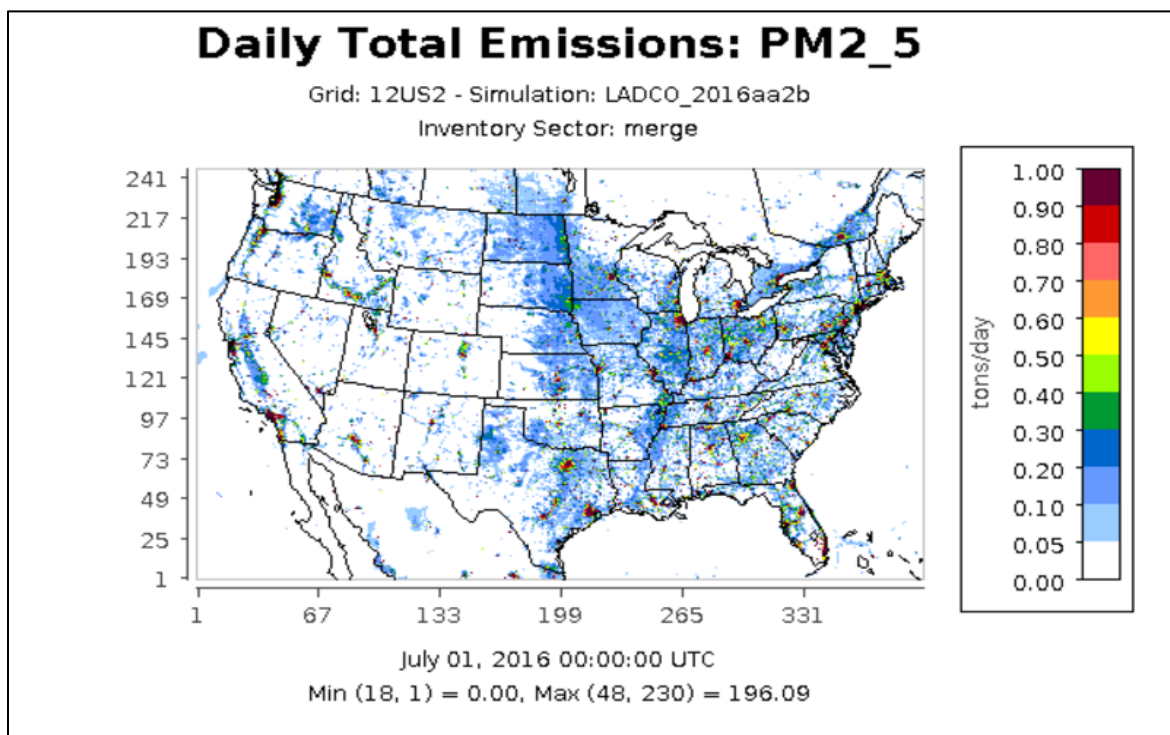
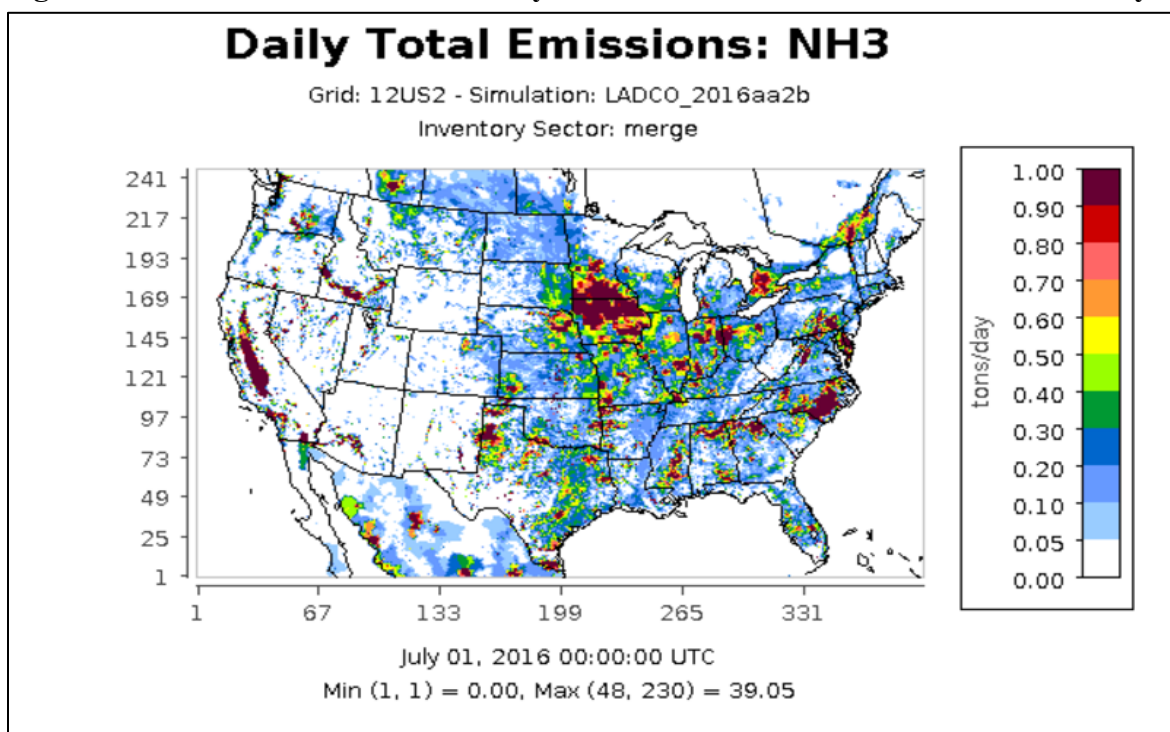
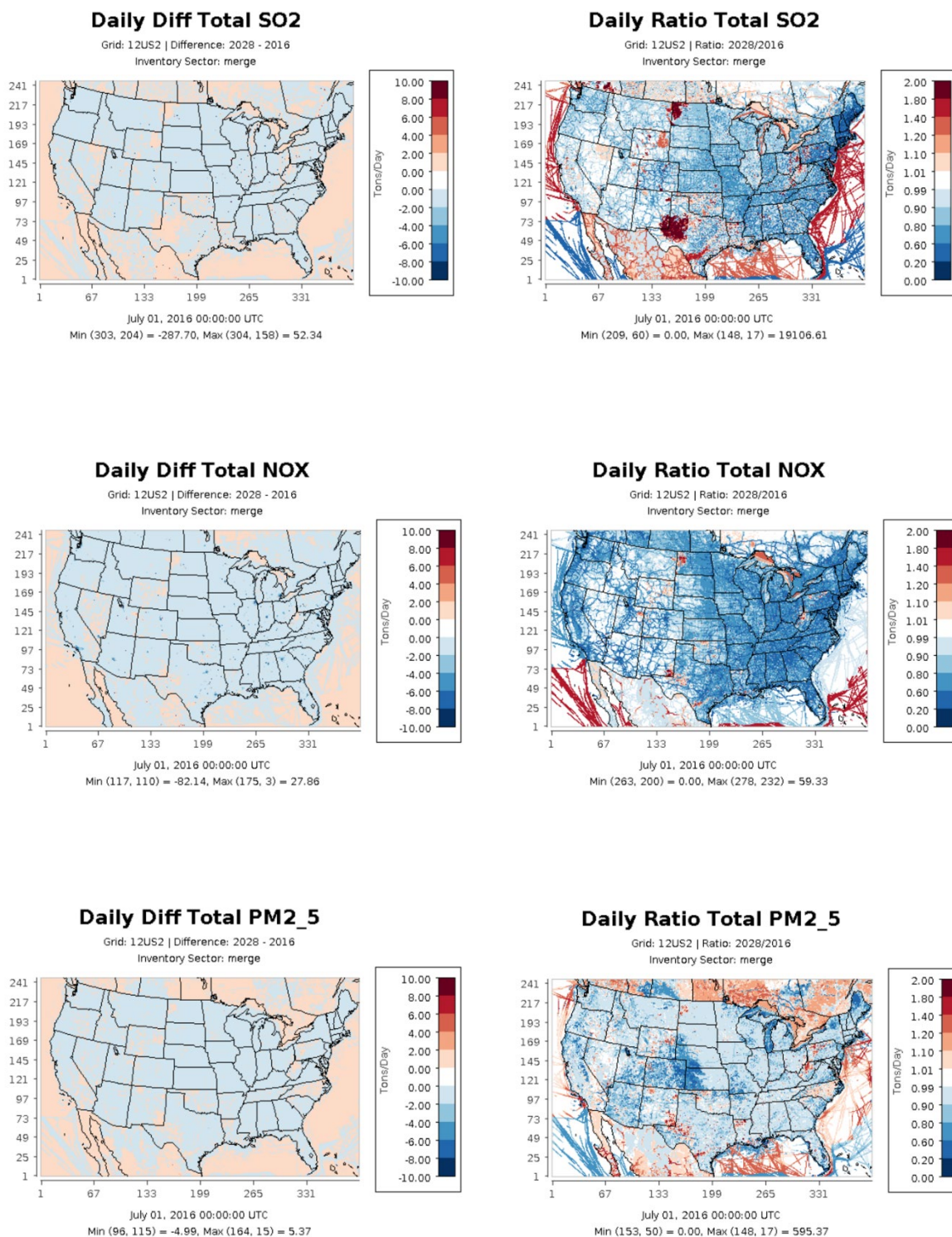


Figure 5-6 Difference Plots of 2016-2028 Daily SO₂ Emissions for Summer Weekday



5.14 Future Year Emissions - 2028

Emission inventories were developed for future year 2028. As stated in EPA’s “Technical Support Document (TSD) Preparation of Emissions Inventories for 2016v1 North American Emissions Modeling Platform, September 2020”, the purposes of preparing the air quality model-ready emissions, emissions from the five NEI data categories are split into finer-grained sectors used for emissions modeling. The significance of an emissions modeling or “platform sector” is that the data are run through the SMOKE programs independently from the other sectors except for the final merge (Mrggrid). The final merge program combines the sector-specific gridded, speciated, hourly emissions together to create CMAQ-ready emission inputs. For studies that use CAMx, these CMAQ - ready emissions inputs are converted into the file formats needed by CAMx.

Table 5-3 presents an overview of the emission sectors in the 2028 platform and how they generally relate to the 2014NEIv2 as their starting point. The platform sector abbreviations are provided in italics. These abbreviations are used in the SMOKE. State and local agencies provided emissions data used in the development of most sectors.

Table 5-3 Platform Sectors for the 2028 Emissions Modeling Case

Platform Sector	Abbreviation	Method for Estimating Future Emissions
EGU Units:	<i>ptegu</i>	ERTAC emissions for 2028 replaced IPM for EGU’s. The IPM was run to create the 2028 emissions. IPM outputs from the January 2020 version of the IPM platform were used (https://www.epa.gov/airmarkets/epas-power-sector-modelingplatform-v6-using-ipm-january-2020-reference-case). For 2028 the 2030 output year was used because the year 2028 maps to the 2030 output year. Emission inventory Flat Files for input to SMOKE were generated using post-processed IPM output data. Temporal allocation for future year emissions is discussed in the EGU-IPM specification sheet for the 2016v1 platform. Point source oil and gas: <i>pt_oilgas</i> First, known closures were applied.
Point Source Oil and Gas:	<i>pt_oilgas</i>	First, known closures were applied to the 2016 <i>pt_oilgas</i> sources. Production related sources were then grown from 2016 to 2017 using historic production data. The production-related sources were then grown to 2028 based on growth factors derived from the Annual Energy Outlook (AEO) 2019 data for oil, natural gas, or a combination thereof. The grown emissions were then controlled to account for the impacts of relevant New NSPS.

Remaining Non-EGU Point:	ptnonipm	First, known closures were applied to the 2016 ptnonipm sources. Closures were obtained from the Emission Inventory System (EIS) and also submitted by the states of Alabama, North Carolina, Ohio, Pennsylvania, and Virginia. Industrial sources were grown using factors derived from the AEO 2019. Rail yard emissions were grown using the same factors as line haul locomotives in the rail sector. Controls were then applied to account for relevant NSPS for reciprocating internal combustion engines (RICE), gas turbines, and process heaters. Reductions due to consent decrees that had not been fully implemented by 2016 were also applied, along with specific comments received by S/L/T agencies.
Airports		Starts with 2017 NEI. Airport emissions were grown using factors derived from the Terminal Area Forecast (TAF).
Agricultural	ag	Livestock were projected based on factors created from USDA National livestock inventory projections published in February 2018. Fertilizer emissions were held constant at year 2016 levels.
Area Fugitive Dust:	afdust, afdust_ak	Paved road dust was grown to 2028 levels based on the growth in VMT from 2016 to 2028. The remainder of the sector including building construction, road construction, agricultural dust, and unpaved road dust was held constant.
Category 1, 2 CMV	cmv_c1c2	Category 1 and category 2 (C1C2) CMV emissions sources were projected to 2028 based on factors from the Regulatory Impact Analysis (RIA) Control of Emissions of Air Pollution from Locomotive Engines and Marine Compression Ignition Engines Less than 30 Liters per Cylinder.
Category 3 CMV	cmv_c3	Category 3 (C3) CMV emissions were projected using a forthcoming EPA report on projected bunker fuel demand. The report projects bunker fuel consumption by region out to the year 2030. Bunker fuel usage was used as a surrogate for marine vessel activity. Factors based on the report were used for all pollutants except NOx. Growth factors for NOx emissions were handled separately to

		account for the phase in of Tier 3 vessel engines. The NOx growth rates from the EPA C3 Regulatory Impact Assessment (RIA) were refactored to use the new bunker fuel usage growth rates. The assumptions of changes in fleet composition and emissions rates from the C3 RIA were preserved and applied to the new bunker fuel demand growth rates for 2028 to arrive at the final growth rates.
Locomotives	rail	Passenger and freight were projected using separate factors. Freight emissions were computed for future years based on future year fuel use values for 2028. Specifically, they were based on 2018 AEO freight rail energy use growth rate projections and emission factors, which are based on historic emissions trends that reflect the rate of market penetration of new locomotive engines.

5.15 2028 Emissions Summary

The tables and figures in this section summarize the emissions used in the LADCO 2016-based 2028 CAMx simulation. Table 5-4 shows the projected 2028 emissions that were factored into the future year 2028 modeling runs and the LADCO state total 2028 annual emissions for the haze species. The emission groups include biogenic and fire projected emissions, which are the same as the 2016 emissions. All anthropogenic emissions were projected using the growth and projection factors, as used by EPA, and shown above in Table 5-3.

Table 5-4 Indiana's 2028 Projected Modeled Emissions

Emission Group	2028 Emissions (tons/year)				
	NH ₃	NO _x	PM _{2.5}	SO ₂	VOC
Biogenics	---	21,381	---	---	279,976
Fires	720	697	3,849	359	10,356
Nonpoint	89,324	30,049	46,254	1,097	130,268
Nonroad	65	18,170	1,518	54	15,928
On-road	2,292	36,034	1,588	321	23,806
Point	2,530	90,558	23,675	82,983	34,049

Table 5-5 below shows the difference in 2016 to 2028 emissions that were modeled. Despite increases in some NH₃ and VOC emissions, overall modeled emissions decreased by a significant amount. The percentage differences in NO_x and SO₂ emissions in particular were substantial and reflect the continued efforts of Indiana and other states to commit to emission reductions throughout all sources in the state. These percentage difference results are shown in Table 5-6.

Table 5-5 2016 - Indiana's 2028 Annual Difference in Emissions by Emission Group

Emission Group	2016 - 2028 Emissions Difference (tons/year)				
	NH ₃	NO _x	PM _{2.5}	SO ₂	VOC
Biogenics	---	0	---	---	0
fires	0	0	0	0	0
nonpoint	-7,616	4,767	635	45	-1,061
nonroad	-9	18,621	1,690	12	4,479
on-road	445	67,660	1,797	295	31,243
point	-1,026	39,205	2,335	44,162	-827

Table 5-6 compares 2028 and 2016 annual haze emissions by inventory group for each LADCO state. Negative numbers in these tables indicate percent emissions reductions in 2028 relative to 2016. Comparisons of the EGU and industrial point source emissions changes between 2016 and 2028 is confounded by the different methods used by the EPA and ERTAC EGU projection models for distinguishing EGU from non-EGU industrial point sources. ERTAC only modeled sources with Continuous Emissions Monitoring System (CEMS) data while EPA does economic projections of all units that sell power to the grid including plants like paper mills and aluminum foundries. Groups that use ERTAC use the EPA projections for these sources that are generate power but do not have CEMS.

Table 5-6 2016 - Indiana's 2028 Percentage Difference in Emissions by Emission Group

Emission Group	2016 - 2028 Emissions Difference (%)				
	NH ₃	NO _x	PM _{2.5}	SO ₂	VOC
Biogenics	---	0.00%	---	---	0.00%
Fires	0.00%	0.00%	0.00%	0.00%	0.00%
NonPoint	9.32%	-13.69%	-1.36%	-3.94%	0.82%
Nonroad	15.23%	-50.61%	-52.68%	-18.34%	-21.95%
On-road	-16.26%	-65.25%	-53.08%	-47.88%	-56.75%
Point	68.25%	-30.21%	-8.98%	-34.73%	2.49%

Figure 5-9 and 5-11 show gridded daily total 2016 NO_x and SO₂ emissions for a winter weekday (based on January 15, 2016) as supplied by LADCO and detailed in Section 4.2.2 in the LADCO Regional Haze 2018-2028 Planning Period TSD, dated June 17, 2021. The emissions represent projected emissions from sources in the U.S., Canada and Mexico located within the modeling domain. The spatial patterns seen in these figures match the patterns in the 2016 emissions figures shown previously.

Overall, both the NO_x and SO₂ emissions are projected to decrease in 2028 relative to 2016 in all of the LADCO states. The NO_x reductions for the anthropogenic sectors (i.e., excluding biogenics and wildfires) range from 28 to 42% with Indiana's NO_x reduction at 42%, driven primarily by reductions in mobile source emissions. The SO₂ reductions are significant, at around 18 to 51% in each of the LADCO states and are driven by reductions in coal fired utility reductions. Indiana's SO₂ reductions are projected to be 34%. Both the NO_x and SO₂ reductions are shown in Figures 5-10 and 5-12.

Figure 5-9 Daily Total Gridded 2028 NO_x Emissions for a Weekday

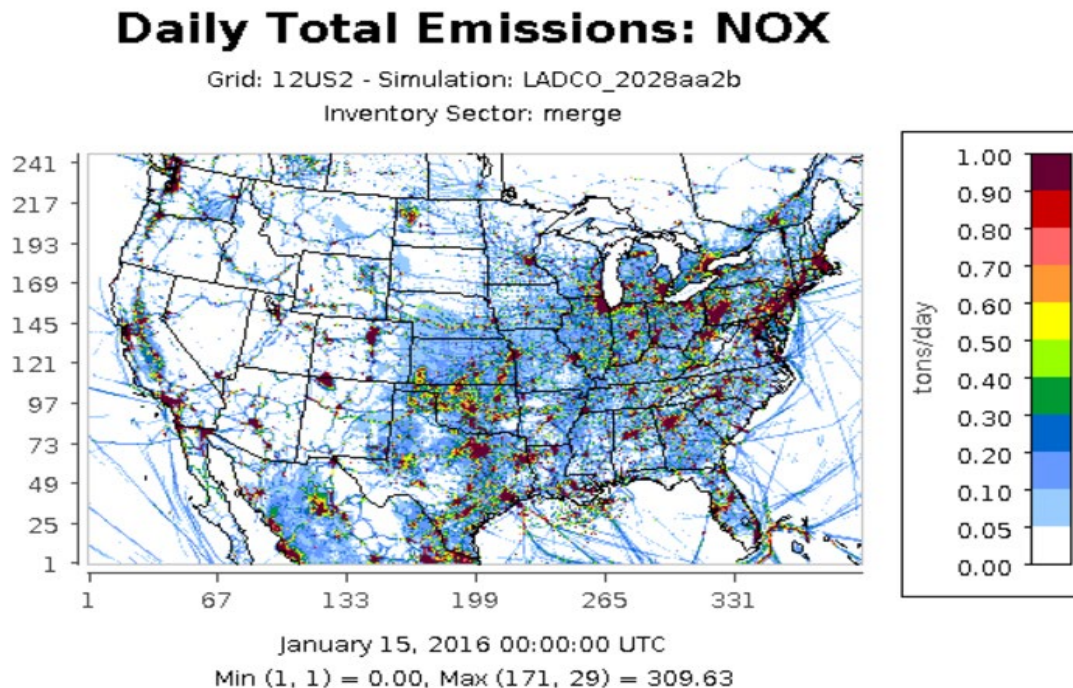


Figure 5-10 Difference (2028-2016) in Daily Total Gridded NO_x Emissions for a Weekday

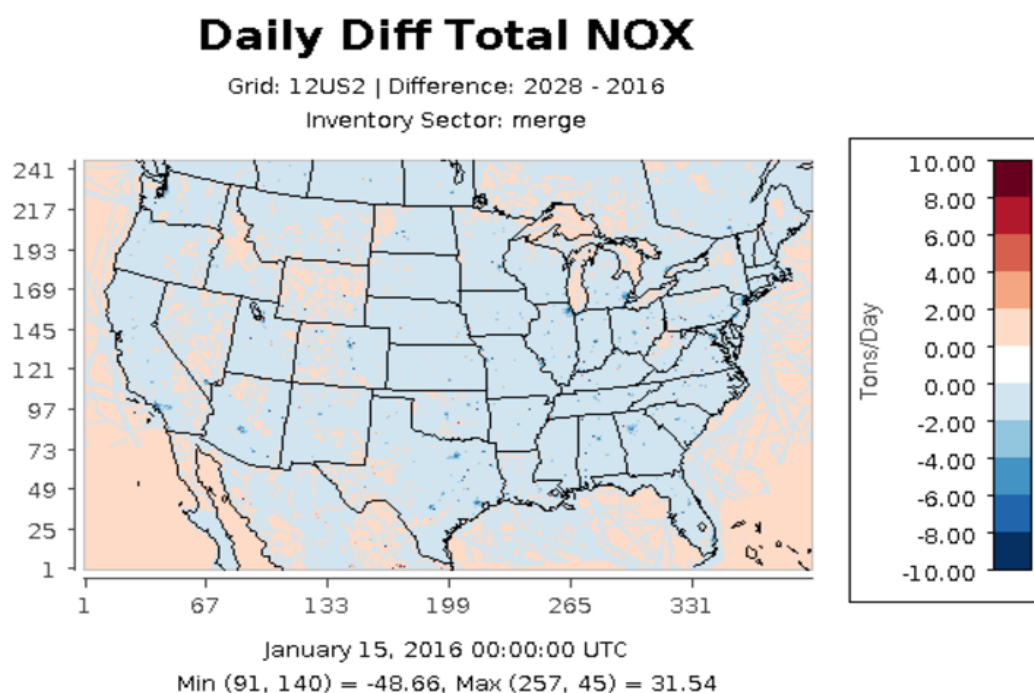


Figure 5-11 Daily Total Gridded 2028 SO₂ Emissions for a Weekday

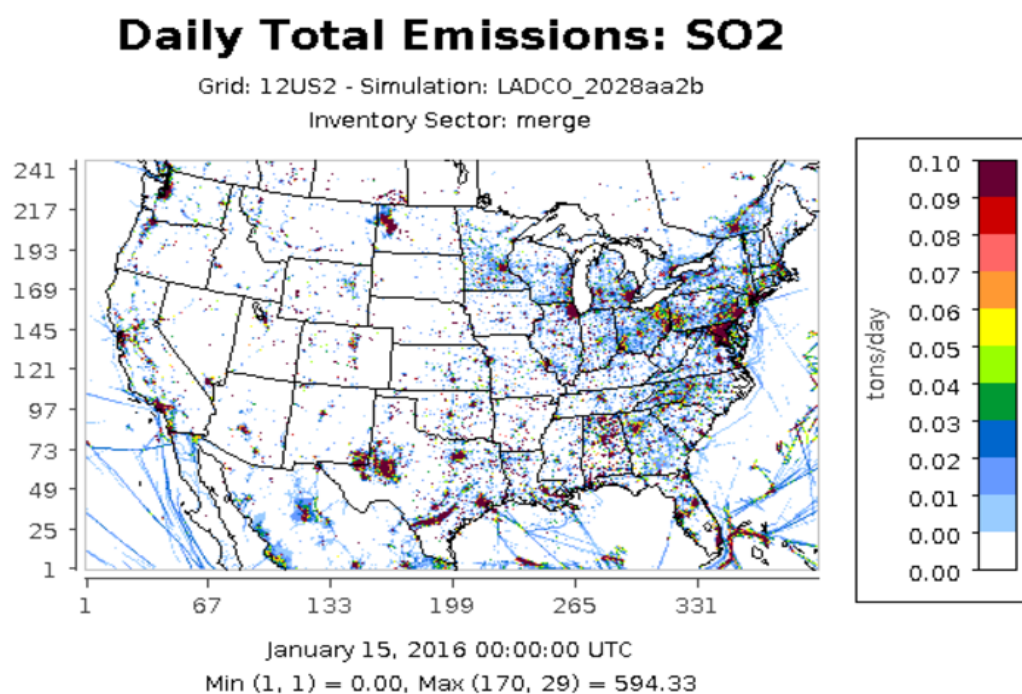
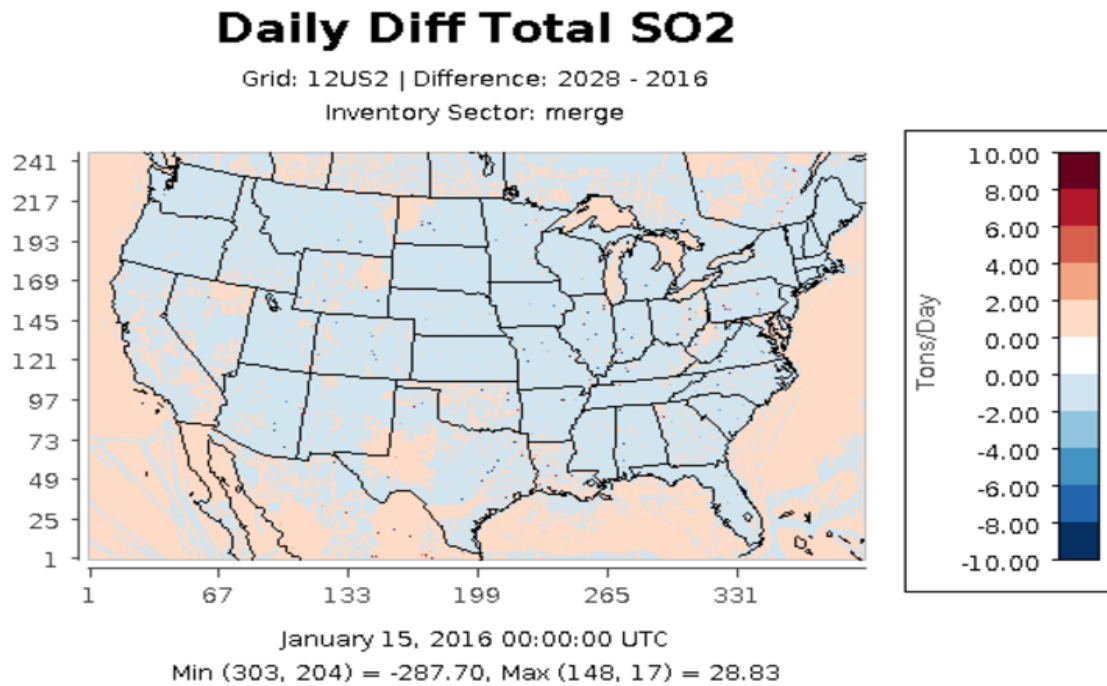


Figure 5-12 Difference (2028-2016) in Daily total Gridded SO₂ Emissions for a Weekday



6.0 MODELING ASSESSMENT

For RH, the calculation of future year conditions assumed: (a) baseline concentrations based on 2000-2004 IMPROVE data, (b) use of the new IMPROVE light extinction equation, and (c) use of EPA default values for natural conditions, based on the new IMPROVE light extinction equation.

Pursuant to EPA’s RH Rule, states must consider several factors in establishing reasonable progress goals for their Class I areas, including the uniform rate of visibility improvement. The uniform rate of visibility improvement values for the 2028 planning year were derived (for the 20% most impaired days) based on a straight line between the baseline concentration value (plotted in the year 2004, end year of the 5-year baseline period) and the natural condition value (plotted in the year 2064, the date for achieving natural conditions). Plots of these “glidepaths” for Class I areas in the eastern U.S. showing the worst 20% most impaired days and best 20% days are presented in Section 23. A tabular summary of measured baseline and modeled future year deciview values for these Class I areas are provided in Table 23-2. This information was taken from the LADCO “Modeling and Analysis for Demonstrating Reasonable Progress for the RH Rule 2018-2028 Planning Period” Technical Support Document (TSD), dated June 17, 2021 attached in Appendix L.

6.1 Regional Haze Modeling Platform

40 CFR Part 51, Appendix W provides modeling guidelines for conducting regional-scale modeling to simulate pollutants impairing visibility. The EPA recommends the use of one of three models and LADCO chose CAMx.

In 2017, a group of multi-jurisdictional organizations, states, and EPA established 2016 as the new base year for a national air quality modeling platform. The group concluded that if only one recent year could be selected, that 2016 would serve as a good base year. Therefore, LADCO provided RH modeling based on the 2016 emission platform taken from the 2016v1 National Emission Inventory Collaborative emissions inventory and the EPA 2016ff CAMx modeling platform. The meteorology and initial and boundary conditions came from the EPA 2016ff CAMx modeling platform. LADCO processed most of the 2016 emissions using the EPA 2016fh_16j SMOKE modeling platform. The CAMx inputs, including the meteorology data simulated with the Weather Research Forecast (WRF) model, emissions data, and boundary conditions represent year 2016 conditions. LADCO used the majority of the data and software provided by EPA for this platform, with a few exceptions described below.

6.2 CAMx Configuration

LADCO based its CAMx air quality modeling platform for this regional haze modeling application on the configuration that the EPA used for their update RH modeling (US EPA, 2019b). LADCO used CAMx 7.0 (Ramboll, 2020) as the photochemical grid model for this application. Similar to the 2011 modeling platform, LADCO was able to leverage data and software elements that EPA distributed for regulatory rulemaking.

Table 6-1 summarizes the CAMx science configurations and options LADCO used for the 2016 and 2028 CAMx modeling for this application. LADCO used the Piecewise Parabolic Method (PPM) advection solver for horizontal transport along with the spatially varying (Smagorinsky) horizontal diffusion approach. LADCO used K-theory for vertical diffusion using the CMAQ-like vertical diffusivities from WRFCAMx. The CB6r4 gas-phase chemical mechanism was selected because it includes the latest chemical kinetic rates and represents improvements over the other alternative CB05 and SAPRC chemical mechanisms as well as active methane chemistry.

LADCO used CAMx to simulate the entire year for 2016 and 2028. LADCO selected a CAMx configuration that was consistent with previous RH modeling applications performed by EPA. EPA (2019b) provides complete details of their 2016 CAMx simulation, including a performance evaluation.

Figure 6-1 shows the EPA transport modeling domain for the continental U.S. A 12-km uniform grid (12US2) covers all of the continental U.S. and includes parts of Southern Canada and Northern Mexico. The domain has 36 vertical layers with a model top at about 17,550 meters (50 mb). LADCO used the same EPA 12-km domain for this project because it supported the use of meteorology, initial and boundary conditions, and emissions data that were freely available from EPA. Additional details to the modeling configuration can be found in Section 3.4 and Table 3-1 in the LADCO Regional Haze 2018-2028 Planning Period TSD, dated June 17, 2021.

Figure 6-1 CAMx 12-km Modeling Domain



Table 6-1 LADCO 2016 CAMx Modeling Platform Configuration Summary

Science Options	CAMx 2016 Configuration
Model Codes	CAMx V7.0
Simulation Period	December 21, 2015 – December 31, 2016
Horizontal Grid Mesh	12 km, 396 col x 246 rows
Vertical Grid Mesh	35 WRF layers (no collapsing)
Grid Interaction	None
Initial Conditions	10-day spin-up on 12 km grid
Boundary Conditions	12km from hemispheric CMAQ
Emissions	
Baseline Emissions Processing	SMOKE, MOVES and BEIS
Emissions Modeling Platform	EPA 2016 “FH” Platform with ERTAC 16.1 EGU Point and hourly CEMs
Chemistry	
Gas Phase Chemistry	CB6r4
Aerosol Chemistry	CF + SOAP
Meteorology	
Model Codes	WRF v3.8
Meteorological Processor	WRFCAMx v4.6
Horizontal Diffusion	Spatially varying
Vertical Diffusion	CMAQ-like in WRF2CAMx
Diffusivity Lower Limit	$Kz_{min} = 0.1$ to $1.0 \text{ m}^2/\text{s}$ or $2.0 \text{ m}^2/\text{s}$
Dry Deposition	Zhang dry deposition scheme (CAMx)
Wet Deposition	CAMx-specific formulation
Gas Phase Chemistry Solver	Euler Backward Iterative (EBI) -- Fast Solver
Vertical Advection Scheme	Implicit scheme w/ vertical velocity update (CAMx)
Horizontal Advection Scheme	Piecewise Parabolic Method (PPM) scheme
Integration Time Step	Wind speed dependent
Source Apportionment	PSAT with 25 state, region, and point source tags

6.3 Meteorological Data

LADCO used the EPA 2016 WRF data for this study (US EPA, 2019c). The EPA used version 3.8 of the WRF model, initialized with the 12-km North American Model from the National Climatic Data Center to simulate 2016 meteorology. Complete details of the WRF simulation, including the input data, physics options, and four-dimensional data assimilation configuration are detailed in the Meteorology Model Performance for Annual 2016 Simulation WRFv3.8 report (US EPA, 2019c). LADCO prepared the WRF data for input to CAMx with version 4.6 of the WRF CAMx software. The 2016 CAMx simulation used all 35 of the WRF vertical layers with no layer collapsing.

6.4 Initial and Boundary Conditions

LADCO used 2016 initial and boundary conditions for CAMx generated by the EPA from a northern hemisphere simulation of the Community Multiscale Air Quality (CMAQ) model (US EPA, 2019d). EPA generated hourly, one-way nested boundary conditions (i.e.,

hemispheric-scale to regional-scale) from a 2016 108-km x 108-km polar stereographic CMAQ simulation of the northern hemisphere. Following the convention of the EPA 2016 RH modeling (EPA, 2019b), LADCO used year 2016 CMAQ boundary conditions for modeling 2016 and 2028 air quality with CAMx.

6.5 Photolysis Rates

LADCO prepared the photolysis rate inputs as well as albedo/haze/ozone/snow inputs for CAMx. Day-specific O₃ column data were based on the Total Ozone Mapping Spectrometer (TOMS) data measured using the satellite-based Ozone Monitoring Instrument (OMI). Albedo were based on land use data. For CAMx there is an ancillary snow cover input that will override the land use-based albedo input. LADCO used the TUV photolysis rate processor to prepare clear-sky photolysis rates for CAMx. If there were periods of more than a couple of days where daily TOMS data were unavailable in 2016, the TOMS measurements were interpolated between the days with valid data; in the case where large periods of TOMS data were missing, monthly average TOMS data were used. CAMx was also configured to use the in-line TUV to adjust for cloud cover and account for the effects that modeled aerosol loadings have on photolysis rates; this latter effect on photolysis may be especially important in adjusting the photolysis rates due to the occurrence of particulate matter (PM) concentrations associated with emissions from fires.

6.6 Landuse

LADCO used landuse/landcover data from the EPA WRF 2016 simulation.

6.7 Spin-Up Initialization

A minimum of ten days of model spin up (e.g., December 21-31, 2015) was used for the 12 km modeling domain. LADCO ran quarterly CAMx simulations, initializing each quarter with a 10-day spin-up period.

Modeling includes base year analyses for 2016 to evaluate model performance and strategy analyses to assess candidate control strategies. The analyses were conducted in accordance with the EPA's modeling guidelines (i.e., "Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM_{2.5}, and RH", EPA 454/R-18-009, November 2018). The RH modeling covers the full calendar year of 2016 for the eastern U.S. and uses 12 and 36 km meteorology and modeling domains using CAMx. This modeling predicted the 2028 visibility, in both inverse megameters and deciviews, at Class I areas throughout the United States on the 20% most anthropogenically impaired days.

Table 6-2 summarizes the LADCO 2016 air quality modeling platform elements.

Table 6-2 Summary of the LADCO 2016 air quality modeling platform components

Platform Element	Configuration	Reference	Data source
Meteorology Data	WRFv3.8	EPA, 2019b	EPA
Initial and Boundary Conditions	2016 Hemispheric CMAQ	EPA, 2019c	EPA
2016 Emissions Data	Inventory Collaborative 2016v1 ERTAC16.1 EGU Point		Inventory Collaborative and ERTAC
2028 Emissions Data	Inventory Collaborative 2016v1 ERTAC16.1 EGU Point		LADCO and ERTAC
Emissions Modeling Platform	EPA 2016fh_16j		EPA
Photochemical Grid Model	CAMxv7.0 beta4	Ramboll, 2018	LADCO

6.8 Model performance

The LADCO RH Modeling Technical Support Document provides details on the model performance of the 2016 CAMx run in Section 6. Here, Indiana briefly summarizes the annual performance. Model performance for PM species is determined by setting goals and criteria for the model's normalized mean bias (NMB), normalized mean error (NME), and the correlation coefficient (r). Performance meeting some criteria is considered minimally successful, while performance meeting a goal is considered ideal.

The 2016 CAMx modeling performs marginally for annual average total PM_{2.5}, nitrate, and sulfate across the LADCO region. In regard to NMB, the model met the performance goal for IMPROVE NO₃ and met the performance criteria for total PM_{2.5}, and SO₄ for the IMPROVE monitoring network, and total PM_{2.5} and NO₃ for the CSN monitoring network. While for NME, no performance goals were met however performance criteria was met for total PM_{2.5}, SO₄, and NO₃ for both monitoring networks. For correlation coefficient, the performance goal was met for CSN total PM_{2.5} and SO₄ and IMPROVE SO₄. IMPROVE total PM_{2.5} met the correlation coefficient criteria. The 2016 CAMx model performance for carbonaceous aerosol was poor due to severe over prediction bias.

7.0 SOURCE SELECTION PROCESS

Section 51.308(f)(2)(i) requires a SIP to include a description of the criteria the state has used to determine the sources or groups of sources it evaluated for potential controls. This section describes the process IDEM used for selecting Indiana sources with the highest visibility impacts at Class I areas for the second implementation period.

7.1 Estimating Baseline Visibility Impacts for Source Selection

The EPA has developed recommendations on developing and applying air quality model-based visibility impact estimates for the selection of sources for subsequent evaluation of

potential emission control measures. The RH Rule does not require states to develop estimates of individual source or source category visibility impacts or use an air quality model for those estimates. Instead of quantifying and considering visibility impacts for the purpose of selecting sources to analyze, a state may also develop and consider a reasonable surrogate metric for such impacts (e.g., the emissions/distance relationship, etc.). Surrogate metric here refers to a quantitative metric that is correlated to some degree with visibility impacts as they would be estimated via air quality modeling. The EPA RH SIP Guidance Document recommends modeling or the following techniques for examining source visibility impacts. Those techniques include:

- 1) Emissions divided by distance (Q/d),
- 2) Trajectory Analysis,
- 3) Residence time analyses,
- 4) Photochemical modeling - either zero-out runs or source apportionment.

Indiana used the Q/d methodology to screen the NO_x and SO₂ emissions to determine which emission sources should be analyzed to conduct four-factor analyses. The four-factor analysis, in turn, is used for evaluation of potential emission control measures to reduce visibility impacts on surrounding Class I areas.

7.2 Trajectory Analyses

Additional information can be provided through trajectory analyses which examine the wind direction on individual days. Directionality of upwind sources and source categories can be established by examining sources that tend to emit pollutants upwind of Class I areas on individual days. Back trajectories start at the Class I area and go backwards in time to examine the path that emissions took to get to the Class I areas.

IDEM conducted back trajectory frequency analyses on each of the 20% most anthropogenically impaired days in 2016 to determine if air from Indiana passed over the Class I area and therefore, Indiana emissions could have potentially contributed to visibility impairment on that day. The backward trajectory frequency analyses were conducted using the National Oceanic and Atmospheric Administration (NOAA) Hybrid Single Particle Lagrangian Integrated Trajectory Model (HYSPLIT) model. These analyses computed archived 48-hour trajectories for each day in the 20% most anthropogenically impaired days in 2016 at each selected Class I area. The Global Data Assimilation System (GDAS) 0.5-degree global meteorology dataset was used. The height analyzed was 500 meters above ground level with model vertical velocity initiated. Trajectory frequency grid resolution was set to 1 degree, with a trajectory starting interval of 6 hours.

The HYSPLIT backward trajectory frequency analysis produced four percentage plots for each day. The first plot shows the number of trajectories passing through a grid square divided by the number of trajectories. The second plot shows the number of end points per grid square divided by the number of trajectories. The third shows the number of end points per grid square divided by the total number of endpoints. The fourth shows the number of endpoints per grid square divided by the maximum number of endpoints in any

grid square. These results will show the amount of time air passes over a certain area that impact the Class I area, thus showing the highest frequency of occurrences of air travelling from a location to the Class I area.

The plots are provided in Appendix C. Shown for each selected Class I area are the days which have a 48-hour trajectory that shows a frequency contribution over Indiana.

7.3 Q/d Screening Analysis for Source Selection

The Indiana sources were identified using the Q/d methodology as described in LADCO's memo "Description of the Sources and Methods Used to Support Q/d Analysis for the 2nd RH Planning Period", dated October 14, 2020 and can be found in Appendix M. The analysis of annual emissions (Q) expressed in tons per year divided by distance in kilometers (d) from the Class I areas, known as Q/d, is used to screen emissions source impacts at downwind receptors in lieu of air quality modeling results. Indiana evaluated its sources with higher NO_x and/or SO₂ emissions taken from 2018 which could potentially have visibility impacts on surrounding Class I areas. These two pollutants were selected for this evaluation as speciated data shows NO_x and SO₂ are the dominant pollutants in the formation of regional haze. 2018 emissions were chosen to represent the most current emissions from the Indiana sources in order to determine the most appropriate visibility impacts as sources are realizing decreasing emissions overall. LADCO and NPS provided Q/d ranking lists based on 2016 emissions, Indiana felt these emissions were not representative of more current operations at its facilities. The 2018 NO_x and SO₂ emissions used for Q/d calculations can be found in Appendix O and E.

A screening threshold Q/d value of 5 was established in order to screen out sources with either low emissions or located at far distances from Class I areas that would not have visibility impacts. This threshold presented a variety of higher emitting sources that would have a potential of impacting surrounding Class I areas; sources that are representative of the majority of Indiana emissions sources. Sources with a Q/d value at 5 or above were selected and evaluated based on the four-factors listed in the CAA to determine if emission controls were necessary. All sources had their highest modeled visibility impacts on Mammoth Caves in Kentucky due to its relatively close proximity to the state. The sources in Indiana that exceeded the Q/d threshold value of 5 are shown in the following table.

Table 7-1 Indiana Sources Exceeding the Q/d Threshold Value

<u>County</u>	<u>County ID</u>	<u>Plant ID</u>	<u>Name</u>	<u>Q/d Value</u>
Floyd	043	00004	Duke - Gallagher	15.0
Gibson	051	00013	Duke - Gibson	134.8
Jasper	073	00008	NIPSCO - R M Schahfer	16.1
Jefferson	077	00001	IKEC - Clifty Creek	65.7
Lake	089	00383	Cokenergy	10.7
Lake	089	00316	Cleveland Cliffs - Indiana Harbor East	10.5
Lake	089	00121	US Steel - Gary Works	6.3
Lake	089	00382	Cleceland Cliffs - Indiana Harbor West	5.3
Lawrence	093	00002	Lehigh Cement - Mitchell	15.7
Pike	125	00002	AES - Petersburg	83.7
Porter	127	00001	Cleveland Cliffs Burns Harbor	42.8
Posey	129	00010	SIGECO - AB Brown	34.5
Posey	129	00002	SABIC - Mt Vernon	5.3
Putnam	133	00002	Lone Star Industries	6.7
Spencer	147	00020	AEP - Rockport	259.5
Sullivan	153	00005	Hoosier Energy - Merom	23.6
Vermillion	165	00001	Duke - Cayuga	36.4
Warrick	173	00007	Alcoa Warrick Operations	80.9
Warrick	173	00002	Alcoa Warrick Power Plant	31.3
Warrick	173	00001	SIGECO - F. B. Culley	25.3

The source listings included EGUs and non-EGUs (steel mills, cement and plastics manufacturers, and aluminum smelter and electric services operations) emission sectors. These sources had the largest NO_x and SO₂ emissions in the state and were screened to have the greatest potential to impact visibility in surrounding Class I areas. Sources above the screening threshold value were required by IDEM to conduct a four-factor analysis with the exception of EGUs. IDEM has addressed Indiana's EGUs with a vigorous analysis, reviewing emissions and modeled visibility impairment results along with expected retirements and shutdowns of coal-fired boilers that will be accounted for in subsequent regional haze implementation periods.

7.4 Reasonable Progress and Four-Factor Analyses

Indiana surmises the EGU sector was evaluated in great detail for the first implementation period of the RH Rule. Based on industry-wide emission control measures mandated by strict regulations and far less reliance on coal over the past decade or more due to alternative power generation; numerous shutdowns and fuel conversions of boilers has occurred to which tens of thousands of tons of NO_x and SO₂ emissions have been reduced in just Indiana alone. Emission trends for both NO_x and SO₂ have shown dramatic decreases in emissions and as a result, IDEM is not requiring four-factor analyses for its EGUs.

The EPA RH SIP Guidance Document states the "key flexibility of the RH program is that a state is not required to evaluate all sources of emissions in each implementation period".

IDEM intends to conduct a review of the EGU sector for the January 31, 2025 progress report, pursuant to 40 CFR 51.308 (g). If necessary, IDEM will evaluate EGUs more in depth for the third implementation period of the RH Rule, to be submitted in 2028. As such, Indiana has focused its visibility impact analyses on non-EGU sources, such as steel mills, cement kilns, plastic manufacturing facilities, and aluminum smelter and electric services operations.

Twenty sources met IDEM's source selection criteria for the RH SIP four-factor analysis. Eleven of the sources are power generating stations with coal-fired electric generating units (EGUs). Instead of conducting a four-factor analysis for the eleven EGU sources for the RH SIP, IDEM chose to perform a reasonable progress analysis that consist of a quantitative analysis of statewide NO_x and SO₂ emission reductions from Indiana's EGU fleet for 2009-2019; photochemical modeling using 2016 NO_x and SO₂ base-year modeled emissions for all existing Indiana EGUs in 2016 to project 2028 emissions; and source apportionment modeling to assess visibility impacts from all EGUs in Indiana. A four-factor analysis will however be conducted for the other nine non-EGUs that met the selection criteria.

Indiana's rational for this approach is based on the guidance that an analysis of control measures is not required for every source in each implementation period. The RH Rule sets up an iterative planning process and anticipates that a state may not need to analyze control measures for all its sources in a given SIP revision. While section 51.308(f)(2)(i) of the RH Rule requires a SIP to include a description of the criteria the state used to determine the sources or groups of sources it evaluated for potential controls, it is reasonable and permissible for a state to distribute its own analytical work for the sources that are not selected for an analysis of control measures for purposes of the second implementation period. In addition, it may be appropriate for a state to consider whether measures for such sources are necessary to make reasonable progress in later implementation periods according to the EPA RH SIP Guidance Document, Section 3 on page 9.

7.5 Assessment of Reasonable Progress at Class I Areas

IDEM assessed each of the Class I areas identified in the LADCO 2016 photochemical modeling results as being impacted by Indiana sources. Information provided by LADCO, technical documents from the other RPOs, and letters received from other states indicating their decisions regarding reasonable progress goals were used to make these assessments.

In determining reasonable progress for RH, Section 169 of the Clean Air Act and EPA's visibility rule requires states to consider four factors:

- Costs of compliance
- Time necessary for compliance
- Energy and non-air quality environmental impacts of compliance
- Remaining useful life of any existing source subject to such requirements

In addition, Section 51.308(f)(2)(iv) of the Regional Haze Rule requires states to consider five additional factors for development of long-term strategies. Of those additional factors, Indiana identified several that are applicable in helping to develop its realistic and comprehensive source list. Those factors include:

- Section 51.308(f)(2)(iv)(A) – Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment. Indiana demonstrates significant emission reductions based on current emissions control strategies at its sources that have provided reduced visibility impairment at all surrounding Class I areas.
- Section 51.308(f)(2)(iv)(B) – Measures to mitigate the impacts of construction activities. Indiana addresses this factor through its Title V operating permit program.
- Section 51.308(f)(2)(iv)(C) – Source retirement and replacement schedules. Indiana addresses the expected retirement and replacement of numerous coal-fired boilers at power plants throughout the state which will be accounted for in subsequent regional haze implementation periods.
- Section 51.308(f)(2)(iv)(D) – Basic smoke management practices for prescribed fire used for agricultural and wildland vegetation management purposes and smoke management programs. Indiana’s existing smoke management practices are adequate in achieving Indiana’s reasonable progress goals, as addressed in Indiana’s initial Regional Haze SIP
- Section 51.308(f)(2)(iv)(E) – The anticipated net effect on visibility due to the projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy. Indiana relates this to uniform rate of visibility improvement (needed to attain natural visibility conditions by 2064). Indiana has used emissions evaluations and regional haze modeling results to address this factor.

Since Indiana has no Class I areas, the states with Class I areas took the lead in establishing reasonable progress goals. Indiana participated in the discussions and provided information to assist in setting the goals with details of these correspondence listed in Appendix K. The states developing the plans addressed the four factors listed in Section 169A(g)(1) of the CAA and developed the uniform rate of progress glidepaths. The following sections summarize these analyses.

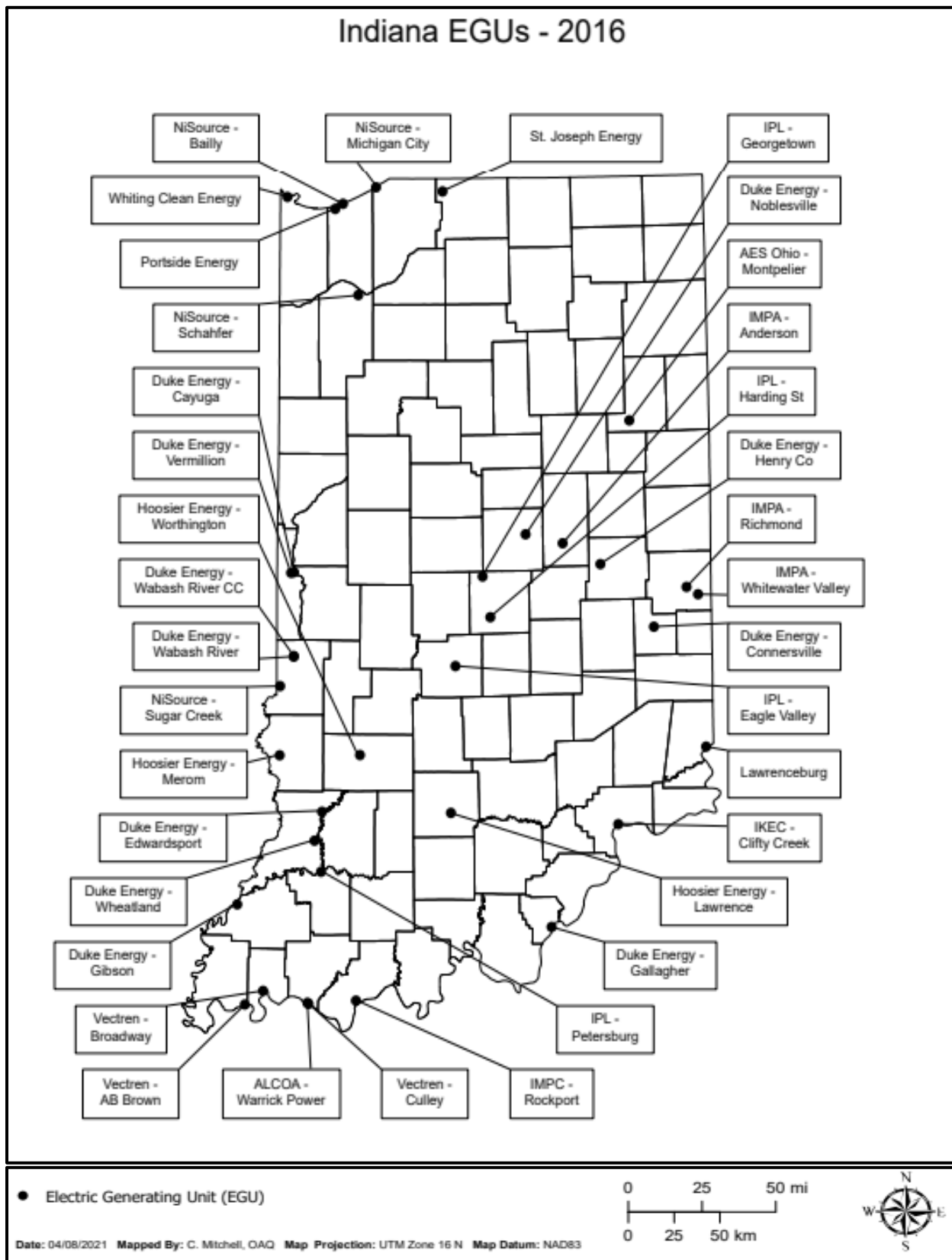
8.0 REASONABLE PROGRESS ANALYSIS FOR INDIANA’S ELECTRIC GENERATING UNITS SELECTED SOURCES

The emissions inventory and contribution assessment performed by LADCO for member states, Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin demonstrated that NO_x and SO₂ emissions were key contributors to visibility impairment at Class I areas in the Northern Midwest region. As previously stated, twenty sources met IDEM’s source selection criteria for the RH SIP four-factor analysis. Eleven of the sources are power generating stations with coal-fired EGUs. This section describes the quantitative analysis of statewide NO_x and SO₂ emission reductions from Indiana’s EGU fleet for 2009-2019; photochemical modeling using 2016 NO_x

and SO₂ base-year modeled emissions for all existing Indiana EGUs in 2016 to project 2028 emissions; and source apportionment modeling to assess visibility impacts by tagging emission source groups, including all EGUs in Indiana, as well as individual EGUs in the state. Section 8.0 in this document was taken from the “Indiana RH SIP for the Second Implementation Period EGUs Reasonable Progress Analysis” document, dated May 18, 2021. This document is a standalone version of Indiana’s EGU Reasonable Progress Analysis which contains some additional data tables in its Appendices. NOTE: See Appendix E for tables that lists the data used to generate the corresponding graphs in Section 8.

Figure 8-1 on the next page shows a map of the existing power generating stations located in Indiana in 2016. All the EGUs at these facilities are included in the LADCO ERTAC 2016 modeling. As such, it should be noted that Indiana used 2018 NO_x and SO₂ emissions to identify sources in IDEM’s Q/d analysis.

Figure 8-1 Map of Indiana's Power Generating Stations in 2016

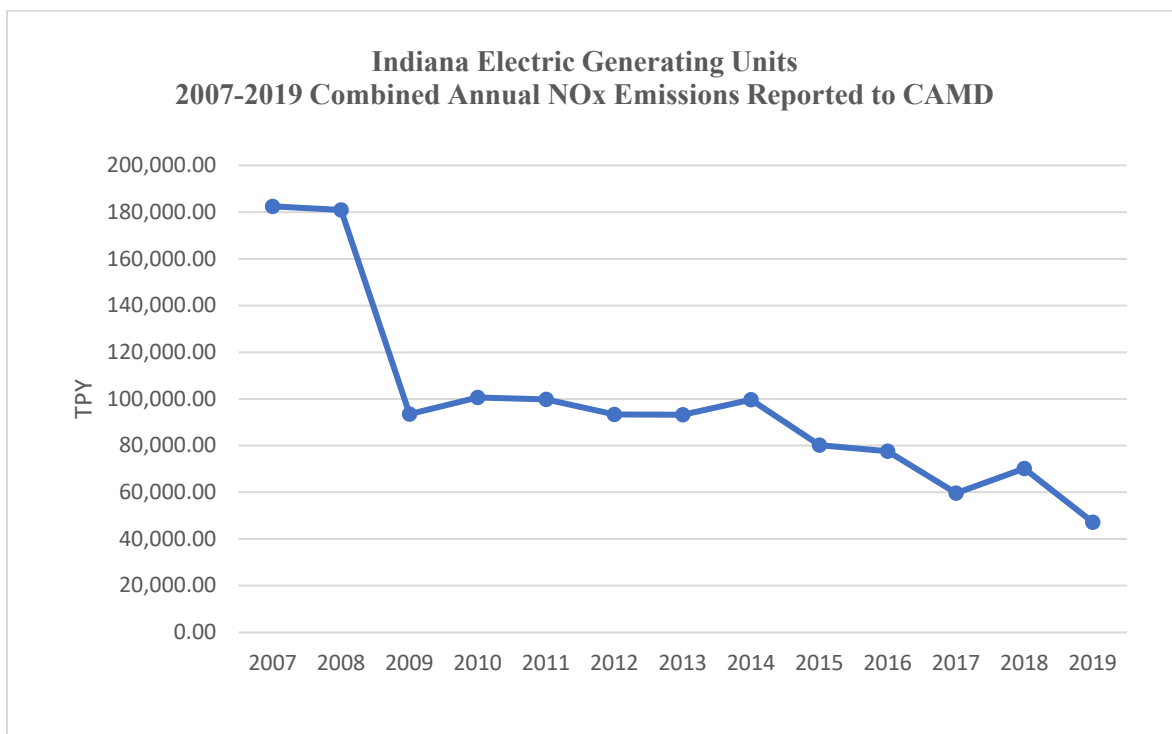


8.1 Indiana EGUs 2009-2019 NO_x and SO₂ Emissions Trends

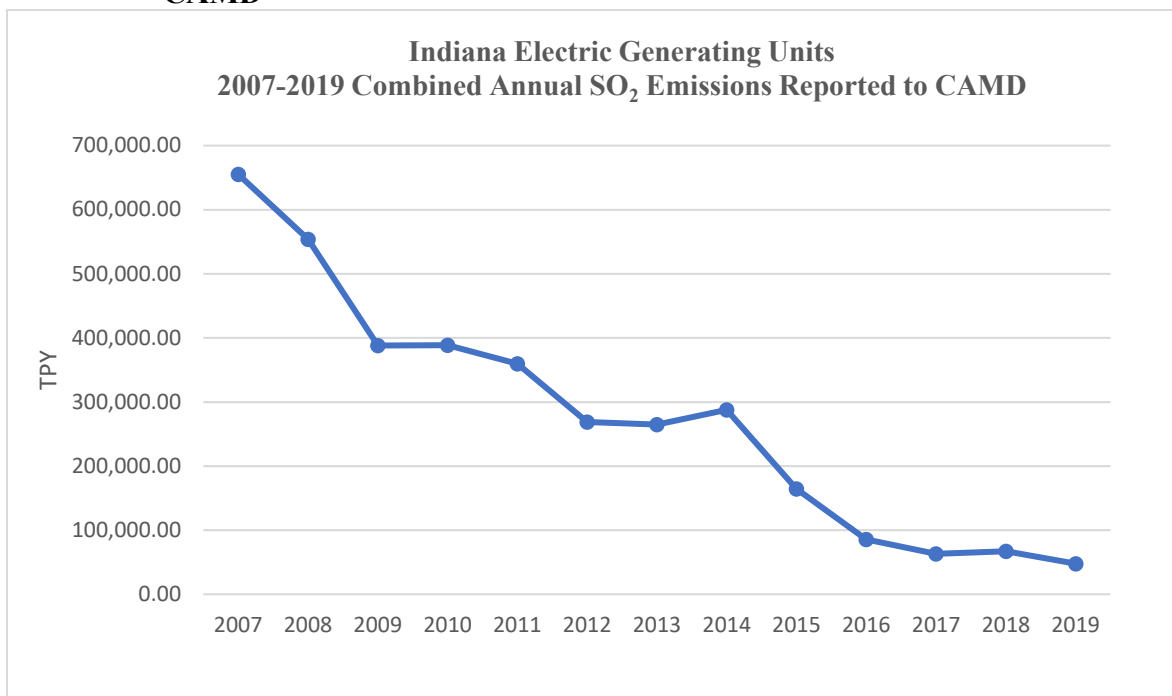
The combined annual NO_x and SO₂ emissions for all EGUs throughout Indiana decreased substantially from 2007 to 2019. Graph 8-1 and Graph 8-2 demonstrate a downward trend in both NO_x and SO₂ statewide annual emissions for Indiana EGUs during the 13-year evaluation period. The combined annual NO_x emissions for all EGUs throughout Indiana decreased by 50%, 46,360 tons, for 2019 compared to 2011 and 39%, 30,350 tons, for 2019 compared for 2016. A more dramatic downward trend is illustrated for statewide annual SO₂ emissions for Indiana EGUs from 2007 to 2019 as shown by the line graph in Graph 8-2. The combined annual SO₂ emissions for all EGUs throughout Indiana were drastically reduced by 81%, 210,180 tons, for 2019 compared to 2011 and 38%, 29,490 tons, for 2019 compared for 2016. Annual NO_x and SO₂ emissions data for Indiana's EGUs from 2007 to 2019 are listed in Tables 2 and 4, respectively, under the "EGUs 2009-19 NO_x and SO₂ Emissions" tabs in Appendix E of this document. The actual emissions data were taken from the Clean Air Markets Division (CAMD) database. The EGUs' combined NO_x and SO₂ emissions date for each year from 2007 to 2019 are listed in Tables 1 and 3, respectively, under the "Combined 2007-19 NO_x and SO₂ Emissions" tabs.

The combined annual NO_x and SO₂ emission reductions for all EGUs throughout Indiana are a direct result of shutdowns, fuel conversions from coal to NG, and pollution control device upgrades and new add-ons that occurred during the 13-year evaluation period. Consent decree agreements with EPA, new federal regulations designed to reduce NO_x and SO₂ (and mercury) emissions from power plants that were implemented after 2009, and revised National Ambient Air Quality Standards have also aided in lowering statewide emissions from all EGUs throughout Indiana from 2007 to 2019.

Graph 8-1 Indiana EGUs 2007-2019 Combined Annual NO_x Emissions Reported to CAMD



Graph 8-2 Indiana EGUs 2007-2019 Combined Annual SO₂ Emissions Reported to CAMD



8.1.1 EGU Retirements and Shutdowns

The following coal fired EGUs were shut down during the 13-year evaluation period, as listed below in Table 8-1. A total of 30 coal fired EGU boilers have been retired and shutdown due to consent decree agreements and new federal and state regulations implemented during the evaluation period.

Table 8-1 Indiana EGUs Retirements and Shutdowns between 2007 and 2019

Facility Name	Unit Identification	Year
Bailly Generating Station	10, 7, and 8	2018
FB Culley Generating Station	1	2007
Cayuga Generating Station	4	2009
Dean H Mitchell	4, 5, and 6	2010
Edwardsport Generating Station	7-1, 7-2, and 8-1	2010
Frank E Ratts Generating Station	1SG1	2016
	2SG1	2015
Harding Street Generating Station	9 and 10	2011
Eagle Valley Generating Station	1 and 2	2011
	4, 5, 6, and 7	2015
R Gallagher Generating Station	1 and 3	2012
State Line Generating Station	3 and 4	2012
Tanners Creek Generating Station	U1, U2, U3, and U4	2015
Wabash River Generating Station	2, 3, 4, and 5	2015
	6	2016

8.1.2 EGU Fuel Switch Conversions

Three EGUs at the Harding Generating Station were converted from coal to NG fuels. Units 50 and 60 were converted in 2015 and Unit 70 in 2016. As a result, annual NO_x emissions decreased by 76% for Unit 50 (62 tons), 72% for Unit and 60 (52 tons), and 50%, for Unit 70 (382 tons) for 2019 compared to 2016. Annual SO₂ emissions from Units 50, 60, and 70 decreased by 74, 70, and 99%, respectively for 2019 compared to 2016 with reductions in tons of SO₂ emissions equal to nearly 1 ton for Units 50 and 60 and 269 tons for Unit 70. The complete results of the fuel switches were not realized until 2017. Table 2 under the “EGUs 2009-2019 NO_x Emissions” Tab and Table 4 under the “EGUs 2009-2019 SO₂ Emissions” Tab, attached in Appendix E of this document lists the actual NO_x and SO₂ emissions for all Indiana EGUs for 2009 - 2019 reported to CAMD.

Table 8-2 Indiana EGUs Fuel Conversions between 2007 and 2019

Facility Name	Unit Identification	Year
Harding Street Generating Station	50 and 60	2015
Harding Street Generating Station	70	2016

8.1.3 EGU Pollution Control Devices Upgrade and Add-on Modifications

Table 8-3 on the next page summarizes the pollution control devices upgrade and new add-on modifications to Indiana’s coal fired EGUs in order to meet consent decree

agreement requirements and new federal and state regulations implemented during the 11-year evaluation period. A more detailed list of the coal fired EGU pollution control devices, control efficiencies, and proposed retirements and shutdowns is attached in Appendix F of this document.

Table 8-3 Indiana EGUs Pollution Control Devices Upgrade and New Add-on Modifications between 2007 and 2019

Facility Name	Unit Id	PM	SO ₂	NO _x	SO ₃ /H ₂ SO ₄	Hg
AB Brown Generating Station	1 & 2				Sorbent Injection	Mercury re-emission chemical injection (2015)
Alcoa Power Plant	4				Reagent Injection	
Cayuga Generating Station	1 & 2			SCR	SO ₃ Mitigation (2015)	
Clifty Creek Generating Station	1, 2, 3, 4, 5, & 6	FGD installed in 2013 (co-benefit of PM removal)	FGD became operational on all six units in 2013		Dry Sorbent Injection installed on units 1 through 5 in 2013	FGD installed in 2013 (co-benefit of Hg removal) with ability to provide chemical additives on as needed basis
FB Culley Generating Station	3				Sorbent Injection	Mercury re-emission chemical injection (2015)
Gibson Generating Station	1, 2, 3, & 5				SO ₃ Mitigation Systems	Mercury re-emission chemical injection system (2015), Calcium Bromide (2015)
	4					Calcium Bromide (2015)
Merom Generating Station	1SG1 & 2SG1		Redesigned FGDs		SO ₃ Mitigation Systems	ACI (2015)
Petersburg Generating Station	1	Upgrade ESP	Upgrade FGD and DSI		Reagent Injection	ACI
	2	Baghouse (2015)	Upgrade FGD and DSI		Reagent Injection	ACI
	3	Baghouse (2016)/ Cold-side ESP	Wet FGD upgraded in 2006		Reagent Injection	ACI
	4	Upgrade ESP	Wet FGD upgraded in 2011		Reagent Injection	ACI
R Gallagher Generating Station	2 & 4		DSI (2010)			
R M Schahfer	14		FGD (2013)	Reagent Injection System		ACI (2014)
	15		FGD (2014)	Reagent Injection System		ACI (2014)
	17		Wet FGD (2010)			
	18		Wet FGD (2009)			
Rockport Plant	MB1 & MB2		DSI - 2015 Enhanced DSI 2020	MB1 SCR - 2017 MB2 SCR - 2020		ACI

8.2 Indiana EGUs Future Year NO_x and SO₂ Emissions

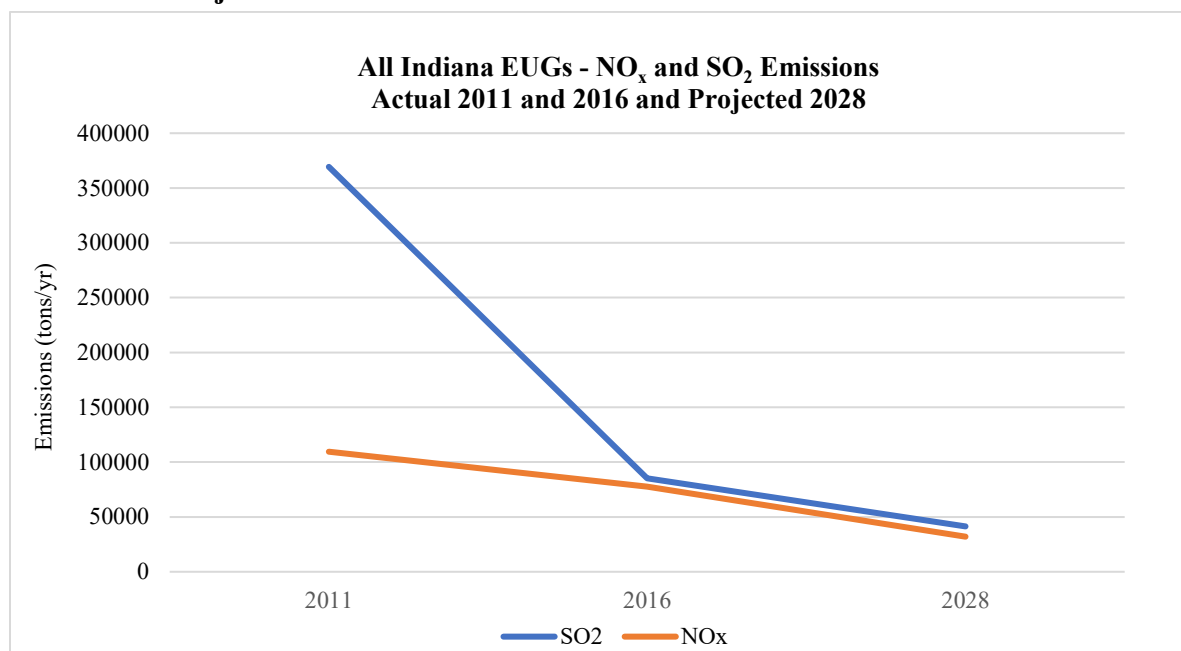
In regard to the photochemical modeling, Table 8-4 summarizes the NO_x and SO₂ emissions for EGUs throughout Indiana for modeled base-years 2011 and 2016 and projected emissions for 2028. The modeled emissions data was provided by ERTAC. The 2011 and 2016 base-year emissions are taken from the CAMD actual emissions data which is the basis of the ERTAC base runs. The net effect from the photochemical modeling evaluation shows dramatic decreases in NO_x and SO₂ emissions statewide, not only actual emissions decreases from 2011 to 2016 but additional projected emissions decreases that are substantial for 2028.

Table 8-4 Indiana EGU Emissions for Base-years 2011 and 2016 and ERTAC Projected 2028

All Indiana EGUs	2011 Modeled Emissions (tons)	2016 Modeled Emissions (tons)	Projected 2028 Emissions (tons)
NO _x	109,507.4	77,777.3	32,015.6
SO ₂	369,325.3	85,328.9	41,374.4

Modeled NO_x emissions were reduced by 29% and SO₂ emissions dropped dramatically with reductions equating to 77% from 2011 to 2016. As shown in Graph 8-3, projected NO_x and SO₂ emissions for Indiana EGUs in 2028 decrease even more with NO_x emissions dropping an additional 59% from 2016 to 2028 and SO₂ emissions reduced by 52%. In total, from 2011 to 2028, Indiana's EGU NO_x and SO₂ emissions are projected to decrease by 71% for NO_x and 89% for SO₂. Graph 8-3 shows the significant downward trend for both NO_x and SO₂ emissions.

Graph 8-3 Indiana EGU Emissions Comparison: 2011 and 2016 and ERTAC Projected 2028



Future year projections are based on the latest LADCO ERTAC modeling analysis. LADCO replaced EPA's IPM EGU inventories in the EPA 2011 and 2016 modeling platforms with inventories derived from the ERTAC EGU model (Mid-Atlantic Regional Air Management Association-MARAMA, 2012). The ERTAC EGU model for growth was developed around activity pattern matching algorithms designed to provide hourly EGU emissions data for air quality planning. The original goal of the model was to create low-cost software that air quality planning agencies could use for developing EGU emissions projections. States needed a transparent model that did not produce dramatic changes to the emissions forecasts with small changes in inputs. A key feature of the model includes data transparency; all of the inputs to the model are publicly available. The open source software includes documentation and a diverse user community to support new users of the software.

The ERTAC EGU model imports base-year CEM data from EPA and sorts the data from the peak to the lowest generation hour. It applies hour specific growth rates that include peak and off peak rates. The model then balances the system for all units and hours that exceed physical or regulatory limits. ERTAC EGU applies future year controls to the emissions estimates and tests for reserve electricity generating capacity, generates quality assurance reports, and converts the outputs to SMOKE-ready modeling files.

ERTAC EGU generates hourly future year emissions estimates. The model does not shutdown or mothball existing units because economics algorithms suggest they are not economically viable. Additionally, alternate control scenarios are easy to simulate with the model. Significant effort has been put into the model to prevent simulations from spawning new coal plants to meet forecasted power demand. As an alternative, the model now allows portability of generation to different fuel types like renewables and NG. Differences between the IPM and ERTAC EGU emissions forecasts arise from alternative forecast algorithms and from the data used to inform the model predictions.

The IPM forecasts used for the EPA "2016fh" modeling platform were based on comments from states and stakeholders received through April 2019. LADCO replaced the IPM EGU forecasts in its modeling with ERTAC EGU version 16.1. The ERTAC EGU 16.1 forecasts used CEM data from 2016 and state-reported changes to EGUs received through September 2020. The LADCO-modified ERTAC EGU 16.1 emissions used for this modeling application represent the best available information on EGU forecasts for the Midwest and Eastern United States available through September 2020.

8.3 Planned Retirements and Shutdowns for Coal Fired EGUs at Indiana Power Plants

Coal fired EGUs are now becoming less financially viable for most companies. New commitments to renewable energy generation are growing each year. Many of these retirements are projected to take place between 5-10 years in the future and are not based on a court order or a permit condition. While the plans for those EGUs with planned retirements of their boilers are a mixture of court ordered requirements and power plants' Integrated Resource Plan (IRP) projections, the overall trend is clear that Indiana is making

reasonable progress. Table 8-5 shows the expected unit retirements by 2028 for many of the EGUs in Indiana.

Table 8-5 Indiana EGUs and Expected Unit Retirements by 2028

County	County ID	Plant ID	Name	Expected Unit Retirements by January 1, 2028 including those not in the Modeling
Floyd	43	4	Duke Energy Indiana, LLC – Gallagher	Units 2 & 4 per the 2019 IRP for Duke and verified with source for a June 2021 retirement.
Gibson	51	13	Duke Energy Indiana, LLC – Gibson	Unit 4 per the 2019 Duke IRP and verified with source by 2026.
Jasper	73	8	NIPSCO - R M Schahfer	Units 14, 15, 17 & 18 per the 2018 IRP and was added to the October 2020 NEEDS update from CAMD, verified with source for 2023 for units 17 and 18. Source stated that units 14 and 15 are accelerating retirement now by the end of 2021.
Jefferson	77	1	Indiana-Kentucky Electric Corporation Clifty Creek	None announced.
Pike	125	2	AES Indiana - Petersburg	AES Indiana Petersburg will retire units 1 and 2 before 2028. A determination was made to retire those units in the modeling in 2021 and 2023, respectively. This decision was made based on AES Indiana determining in their 2019 Integrated Resource Plan (IRP) that retiring those units was the "preferred low-cost option", in addition these units were identified in U.S. EPA's 2020 NEEDS update from CAMD as retiring. Finally, the source confirmed the expected retirements. Finally, AES-Petersburg is now operating under a federal Consent Decree agreement with the United States and State of Indiana (Civil Action No. 3:20-cv-202-RYL-MPB, found at www.epa.gov/sites/default/files/2020-09/documents/indianapolispowerlight-cd.pdf) and will be subject to NO _x and SO ₂ limitations for 2025 and 2026 as follows: operate the coal-fired Units 1 through 4 at the Petersburg Station so the Units combined do not emit SO ₂ in excess of an annual tonnage limitation of 10,100 tons per year and operate the coal-fired Units 1 through 4 at the Petersburg Station so the Units combined do not emit NO _x in excess of an annual tonnage limitation of 8,500 tons per year.
Posey	129	10	SIGECO - AB Brown	Units 1 & 2 are set to retire in 2023 per the 2019-2020 IRP and the dates were verified with the source.

Spencer	147	20	AEP Indiana Michigan Power Company dba American Electric Power - Rockport Plant	Rockport Plant, which is owned by AEP Indiana Michigan Power Company, AEP Generating Company, and a group of unaffiliated financial investors is operated by AEP Indiana Michigan Power Company. Under the terms of the Fifth Modification of the AEP System Eastern Fleet NSR Consent Decree signed on July 17, 2019 (www.govinfo.gov/content/pkg/FR-2019-06-07/pdf/2019-11948.pdf), Rockport Plant must install and operate Enhanced Dry Sorbent Injection Systems by June 1, 2020, on Unit 2 and by December 31, 2020 on Unit 1. SO2 was further limited to 10,000 tons per year from both units combined starting in 2021 through 2028 and reduced to 5,000 tons per year beginning in 2029, concurrent with the required retirement of Unit 1 by December 31, 2028. The modification requires compliance with a 0.15 lb/MMBtu 30 day rolling average SO2 emission rate on the combined stack beginning with the 30th SO2 operating day on the combined stack after January 1, 2021. The modification further required the installation and operation of SCR on Unit 2 by June 1, 2020 (SCR was installed on Unit 1 in 2017). In addition, the modification requires compliance with a 0.09 lb/MMBtu 30 day rolling average NOx emission rate on the combined stack beginning with the 30th NOx operating day on the combined stack after January 1, 2021. Both units at Rockport are included in the modeling for 2028.
Sullivan	153	5	Hoosier Energy Rec Inc - Merom	In the October 2020 NEEDS update from CAMD (IPM v5.15 CSAPR update retired by 2024). Retirements are also in the 20-year plan and included in the November 2020 IRP for projected retirement in 2023.
Vermillion	165	1	Duke Energy Indiana LLC - Cayuga	Unit 1 & 2 to retire per the 2019 Duke IRP. Verified with the source for a 2028 retirement.
Warrick	173	2	Alcoa Warrick Power Plant - AGC Division	Per 2019-2020 Vectren IRP exit agreement to purchase power in 2023. Unit will still operate in some capacity beyond 2023.
Warrick	173	0	SIGECO - F. B. Culley	Unit 2 projected to retire in 2023 per 2019-2020 Vectren IRP and the date was verified with source.

In addition, Indiana's coal-fired boilers will continue to dwindle in number after 2028. Based on long-range projections and Integrated Resource Plans (IRPs), several utilities are planning on further retirements of boilers beyond 2028; and are planning on retiring boilers at their facilities during the third implementation period of the Regional Haze. The following units are projected to retire in the next planning period for Regional Haze.

Table 8-6 Indiana EGUs and Expected Unit Retirements beyond 2028 as used in the ERTAC Model

ORIS	Unit ID	Facility	State	ERTAC Region	Fuel/Unit Type	Generation capacity (MW)	2016 BY Annual SO2 (tons)	2016 BY Annual NOx (tons)	2028 FY Annual SO2 (tons)	2028 FY Annual NOx (tons)	Retirement Date
990	GT4	IPL - Harding Street	IN	RFCW	simple cycle g	86	0	53	1	132	1/1/44
990	GT5	IPL - Harding Street	IN	RFCW	simple cycle g	88	0	39	1	77	1/1/30
990	GT6	IPL - Harding Street	IN	RFCW	simple cycle g	199	1	28	3	129	1/1/30
6113	1	Gibson	IN	RFCW	coal	753	1,807	1,887	1,990	2,204	1/1/38
6113	2	Gibson	IN	RFCW	coal	720	2,340	2,953	2,619	2,092	1/1/38
6113	3	Gibson	IN	RFCW	coal	677	2,114	3,019	2,296	1,988	1/1/34
6113	5	Gibson	IN	RFCW	coal	728	5,495	3,273	6,095	2,337	1/1/34
6166	MB1	Rockport	IN	RFCW	coal	1,394	11,401	6,043	4,912	4,334	12/31/28

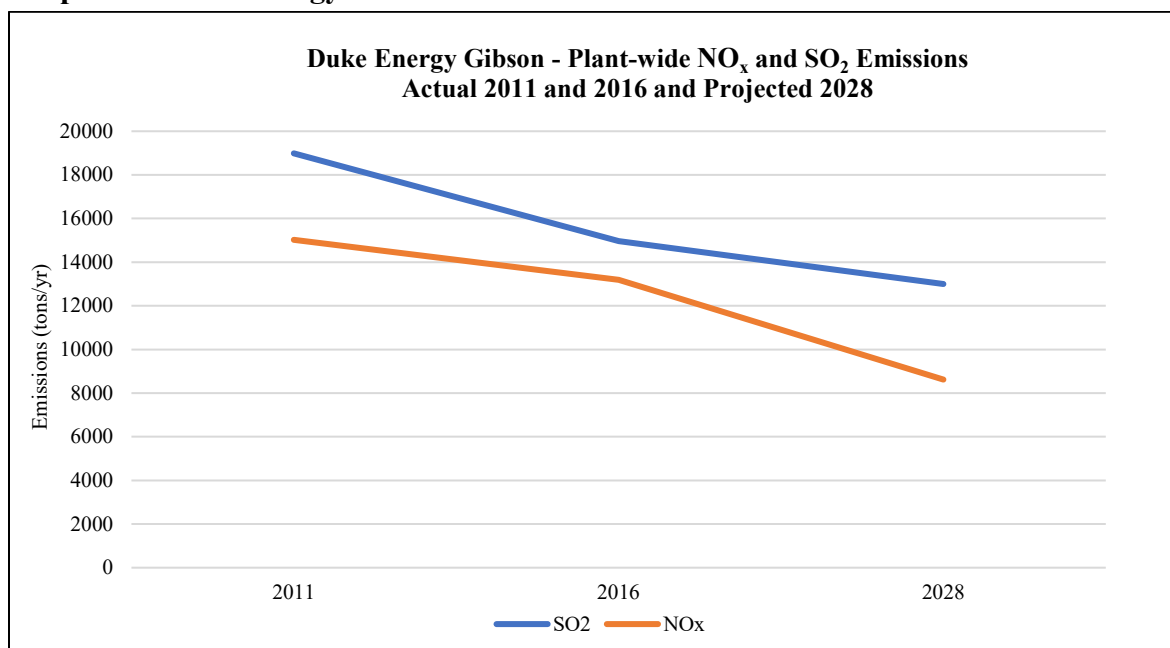
To pursue additional emissions reductions through the use of new emission control equipment or emissions limitations is not desired as a cost-effective method and will only drive utility rates even higher. As will be shown below, the emissions reductions and modeling results demonstrate that visibility impairment from Indiana EGUs in total are decreasing as total light extinction at most all Class I areas is decreasing.

8.4 Duke Energy, Inc - Gibson Generating Station

Duke Energy, Inc (Duke Energy)- Gibson Generating Station (Gibson) is located in Gibson County, in the southwestern portion of Indiana. It is a stationary electric utility generating station with a maximum generating capacity of 3,646 megawatts among five dry bottom, pulverized coal-fired boilers. Controls for these units include wet limestone fluidized-gas desulfurization units controlling SO₂ emissions with control efficiencies above 93% (based on source calculations) and selective catalytic reduction (SCR) systems for NO_x emissions with control efficiencies above 81% (based on source calculated control efficiencies listed in Table 8 of Appendix F).

Gibson's EGUs NO_x emissions are projected to be reduced from 2016 to 2028 by 35% or almost 4,600 tons while SO₂ emissions are estimated to be reduced by 13% or nearly 2,000 tons. Graph 8-4 shows the actual emissions changes that have occurred and changes in emissions projected by 2028 based on demand for power generation from Gibson's EGUs.

Graph 8-4 Duke Energy Gibson - SO₂ and NO_x Emissions Trends



Duke Energy's IRP from 2019 was updated to reflect the advancement of several of their existing coal fired EGUs. Gibson is projected to accelerate retirements of Units 1, 2, 3, and 5; however, Unit 4 is the only unit expected to retire before 2028. These retirements are

part of Duke Energy’s overall plan to move to a more diversified clean energy portfolio. The retirement date for Gibson’s Unit 4 was confirmed with the source in November 2020.

The projections for 2028 are determined by the ERTAC emissions model, which allocates power generation from units that will be retired before 2028. The overall emissions from each facility will be reduced because of the unit shutdowns but individual unit emissions may be slightly higher than their 2016 emissions due to power demand and limited coal-fired power generation capacity with retirements of other boilers. For Gibson’s future emissions projections, Units 1, 2, 3, and 5 may be utilized more to meet the electricity demands without Unit 4; it is important to point out that even if the remaining units are utilized slightly more they are all still required to meet previously established limits. Gibson’s unit utilization rates, both for base-year 2016 and future year 2028, are shown in Table 8-7.

Table 8-7 Gibson Generating Station’s 2016 and Projected 2028 Utilization Rates for Units 1-5

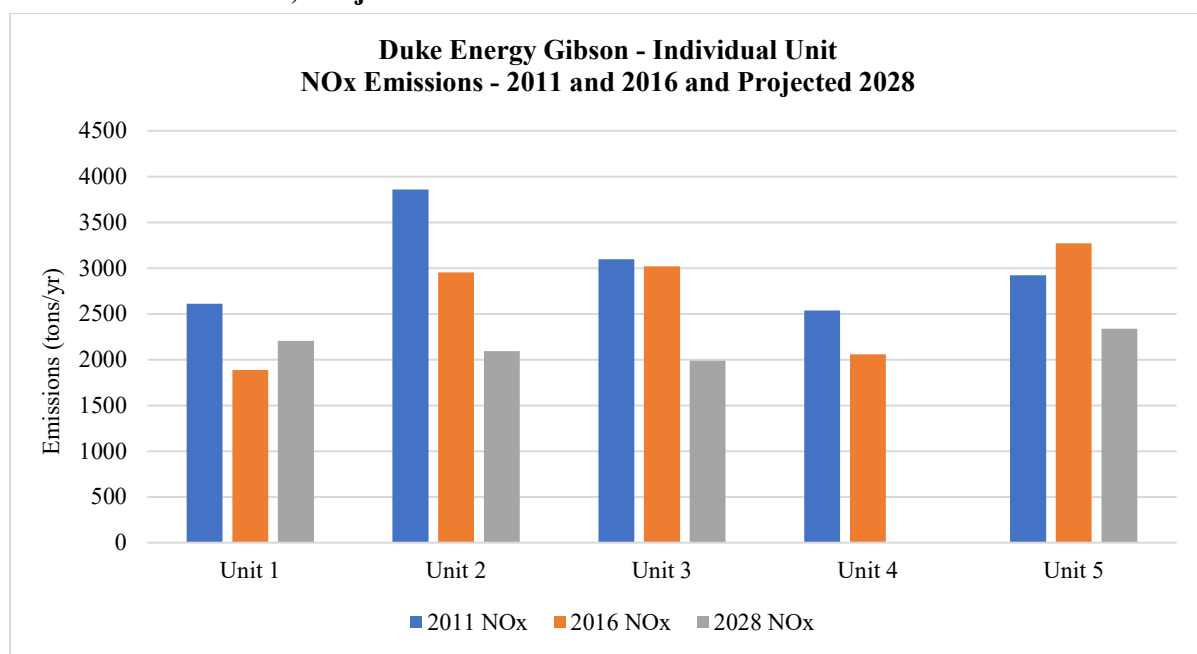
ORIS-ID	Unit ID	Facility	BY-UF 2016 ERTAC	FY-UF 2028- ERTAC	Percentage Change in Utilization
6113	1	Gibson Generating Station	0.4701	0.5175	10.09%
6113	2	Gibson Generating Station	0.6340	0.7097	11.93%
6113	3	Gibson Generating Station	0.6157	0.6688	8.63%
6113	4	Gibson Generating Station	0.5483	Retired	-100.00%
6113	5	Gibson Generating Station	0.5726	0.6351	10.91%

These utilization rates will impact the 2028 emissions from each of the existing units; yet the overall NO_x and SO₂ emissions from the facility will decrease because of the retirement of Unit 4. In the ERTAC emissions tool, the utilization fraction as calculated from the 2016 base-year data will be used to determine dispatch order of electricity to the power grid for units that were operating in the base year. Utilization fraction is the ratio of the total average heat input to the maximum heat input for a unit. It is calculated using the following formula: total average annual heat input/(maximum hourly rated capacity x 8,760 hours/year). For future year emissions projections, the ERTAC tool will dispatch generation to the coal unit fuel type according to the hourly hierarchy order up to the maximum ERTAC annual utilization fraction for that fuel/unit type bin. In the case of coal, no unit will run above 90% utilization rate in the emission model.

In the case of Gibson and the retirement of Unit 4, before the demand for additional power results in a need to make up electric generation within ERTAC’s emissions model, the demand is met by other coal units at the facility based on the growth rates for coal in the ERTAC tool. Gibson’s future year utilization rates among Units 1, 2, 3 and 5 vary from the 2016 base-year to the 2028 projection year as a result of the retirement of Unit 4 in order to meet anticipated electricity demands based on less coal-fired power generation capacity.

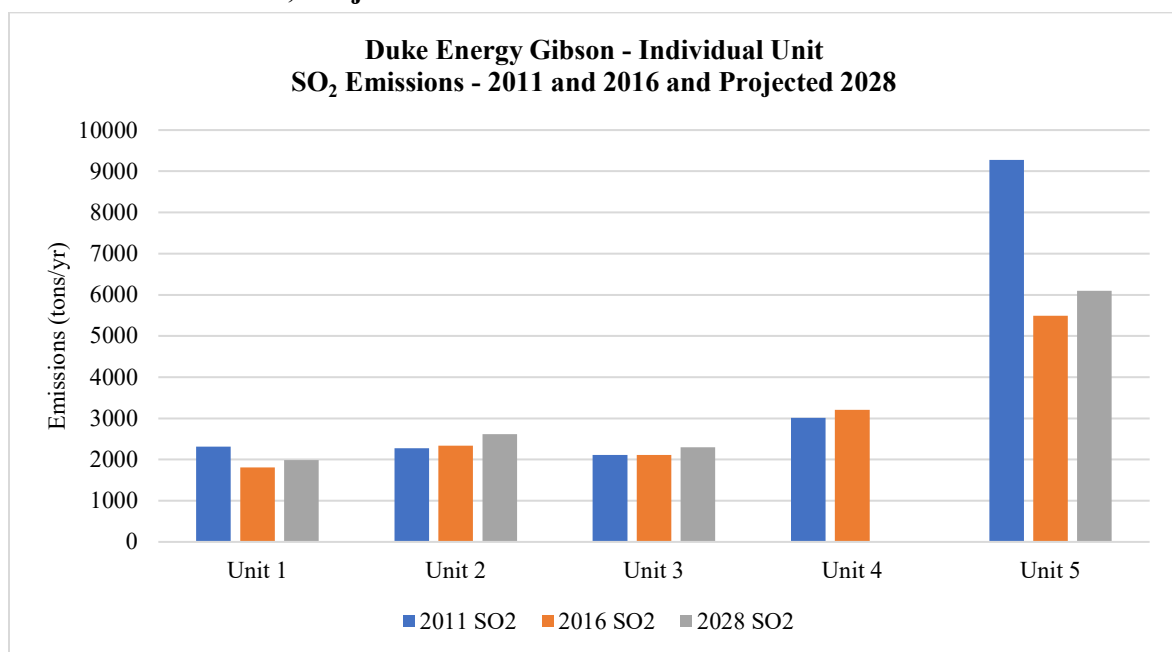
Graph 8-5 shows the unit-by-unit comparison of NO_x emissions at the Duke - Gibson power plant. Unit 1 shows a slight increase in NO_x emissions in 2028. This is due to lower than usual heat input for this unit in 2016, according to CAMD data as listed in Appendix E, combined with an anticipated increase in utilization as a result of Unit 4's retirement. . As such, the projected heat input for Unit 1 in 2028 is higher than the unit's heat input in 2016 resulting in higher projected NO_x emissions for Unit 1 in 2028; even though, overall NO_x emissions at Gibson are projected to decrease by 35% from 2016 to 2028 due to lower projected NO_x emissions from the other three units. The lower projected NO_x emissions from Units 2, 3, and 5 are a direct result of CSAPR and the change to Indiana's NO_x Ozone Season budget in the Revised CSAPR Update Rule, which allots a much lower budget by 2028, while the lower projected SO₂ emissions are a direct result of MATS.

Graph 8-5 Unit Comparison of Duke Energy Gibson's NO_x Emissions - Actual 2011 and 2016, Projected 2028



Graph 8-6 shows the unit-by-unit comparison of SO₂ emissions at the Duke - Gibson power plant. Note the slight increase in emissions at each of the four remaining units, this demonstrates the increase in utilization based on Unit 4's retirement, likely due to the increase electricity demand to make up for lost generation from Unit 4. Overall SO₂ emissions at Gibson are projected to decrease by 13% from 2016 to 2028.

Graph 8-6 Unit Comparison of Duke Energy Gibson's SO₂ Emissions - Actual 2011 and 2016, Projected 2028

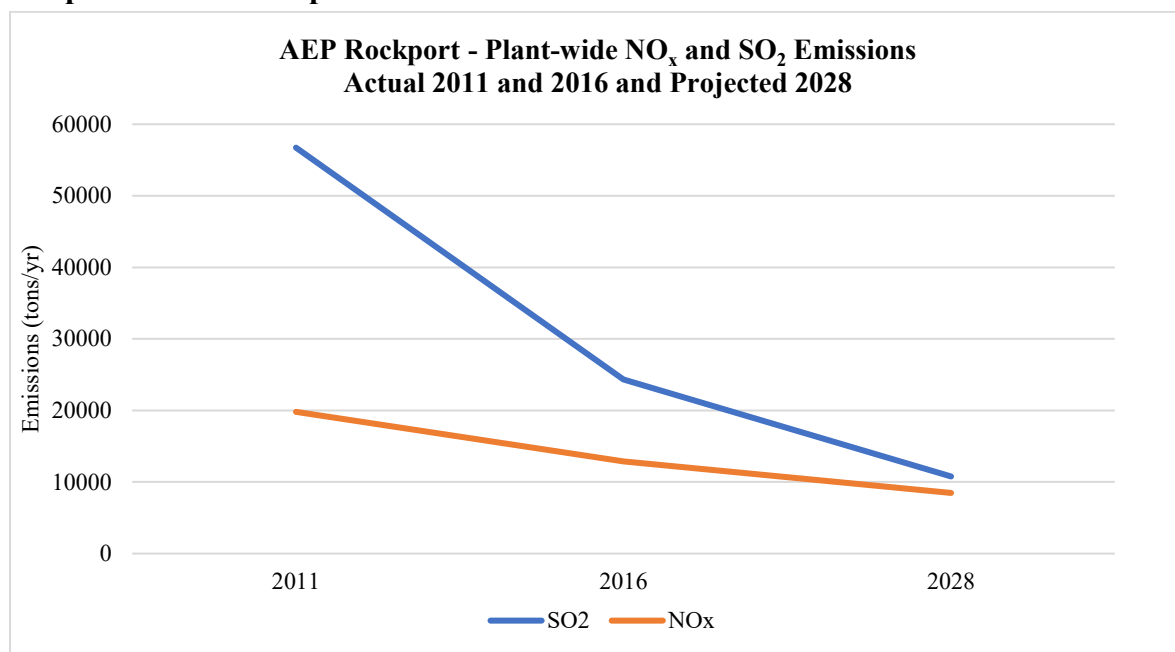


8.5 Indiana Michigan Power Company, dba American Electric Power - Rockport Plant

Indiana Michigan Power Company, dba American Electric Power (AEP) - Rockport Plant (Rockport) is located in Spencer County, in the southern portion of Indiana. It is a stationary electric utility generating plant with a maximum generating capacity of 2,774 gross megawatts with two identical pulverized coal opposed wall fired dry bottom wall fired steam generators identified as Units 1 and 2 with Boilers MB1 and MB2, respectively. SO₂ controls for these units include dry sorbent injection (DSI) system operated since 2015 with a control efficiency of nearly 50% from installation until upgraded to enhanced DSI in 2020 (see Table 8 of Appendix F for source calculated control efficiencies). The enhanced DSI is intended to increase the removal efficiency to in excess of 75% to allow compliance with the federal Consent Decree, lodged by the Department of Justice, United States, et al. v. American Electric Power Service Corp. (www.govinfo.gov/content/pkg/FR-2019-06-07/pdf/2019-11948.pdf), requirements that went into effect in 2020. NO_x control is supplied by existing low-NO_x burners/overfire air systems (LNB/OFA) along with SCRs installed on Unit 1 in 2017 and Unit 2 in 2020. Over the past 5 years, NO_x control has been observed at or above the 57% level at the stack.

Rockport NO_x emissions are estimated to be reduced by over 4,400 tons by 2028 or by 34% from 2016 emission levels. SO₂ emissions are undergoing greater reductions with over 13,500 tons reduced or 56% of the 2016 SO₂ emission levels by 2028 as demonstrated in Graph 8-7.

Graph 8-7 AEP Rockport - NO_x and SO₂ Emissions Trends



Rockport is required under the Fifth Modification of the AEP Eastern Fleet NSR Consent Decree, entered on July 17, 2019 (www.govinfo.gov/content/pkg/FR-2019-06-07/pdf/2019-11948.pdf), to install and continuously operate dry sorbent injection systems on Units 1 and 2 by 2015, and enhanced dry sorbent injection systems on Unit 2 by June 1, 2020, and December 31, 2020 on Unit 1 and Rockport is meeting these requirements currently. Starting with the 30th stack operating day, as defined in the Fifth Modification, Units 1 and 2 are required to meet a 30-day rolling average of 0.15 lb/MMBtu SO₂. SO₂ emissions are also required to be capped plant-wide in the Fifth Modification at 10,000 tons on an annual basis in between 2021 and 2028. Beginning in 2029 that plant wide total cap is lowered to 5,000 tons per year, concurrently with the retirement of Unit 1 (MB1) by no later than December 31, 2028. In addition, Rockport was required to install and continuously operate a SCR on Unit 1 (MB1) by December 31, 2017 and Unit 2 (MB2) by June 1, 2020; Rockport Plant met these requirements. The SCRs shall maintain a 30-day rolling average NO_x emissions on the common stack of 0.09 lb/MMBtu beginning with the 30th stack operating day in 2021, as defined in the Fifth Modification. Both units at Rockport are included in the modeling for 2028.

The projections for 2028 are determined by the ERTAC emissions model, which allocates power generation from units that will be retired before 2028. In Graph 8-7 above, emissions are depicted for 2011, 2016 and 2028 and do not reflect emission reductions that occur between 2016 and 2028 because the modeling analysis only evaluated 2016 and 2028, respectively. In addition, modeled emission for SO₂ in 2028 are above the 10,000

ton per year cap for SO₂ per the consent decree as a result of the rates used in the model to estimate the 2028 emission. In addition, NO_x emissions used in the ERTAC model run version 16.1 are slightly higher than the 0.09 lb/MMBtu rate required by the consent decree. This results in a 2028 projection that is slightly higher than the agreement allows and will be adjusted downward in the next version of ERTAC projections. The result of these overestimates of emissions will be a more conservative analysis in 2028.

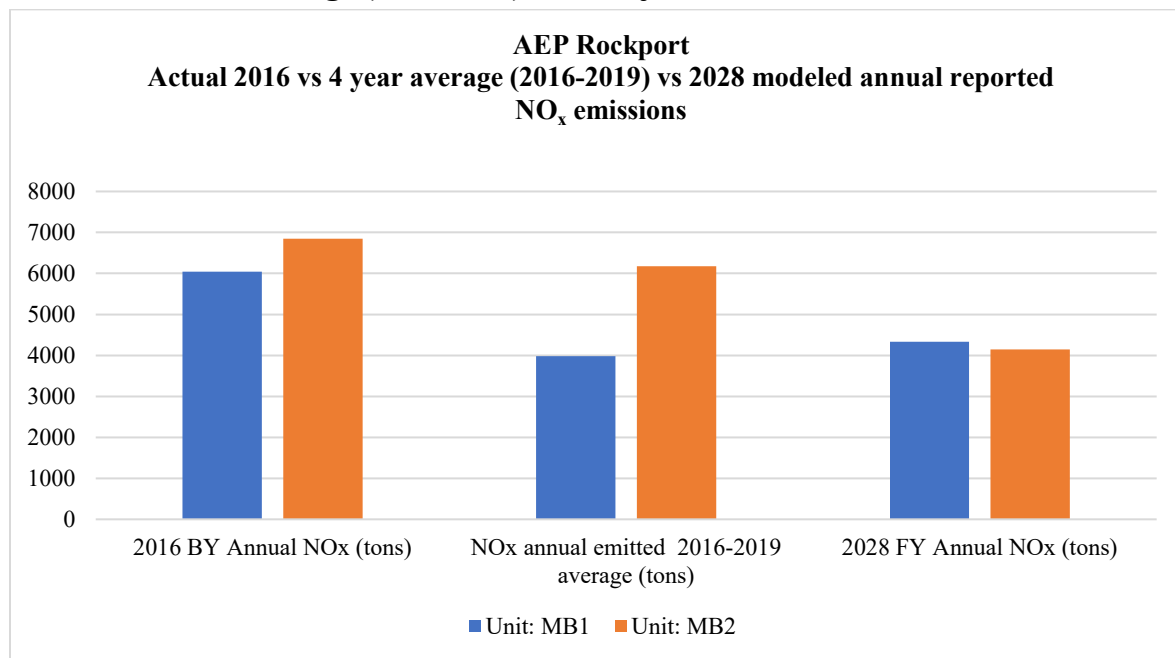
Rockport's ERTAC future emission projections for Units MB1 and MB2 increase slightly from 2016 to 2028 due to shifts in demand across the grid as other coal-fired units retire in the modeling analysis. Rockport's unit utilization rates, both for base-year 2016 and future year 2028, are shown in Table 8-8.

Table 8-8 Rockport Plant's 2016 and Projected 2028 Utilization Rates for Units MB1 and MB2

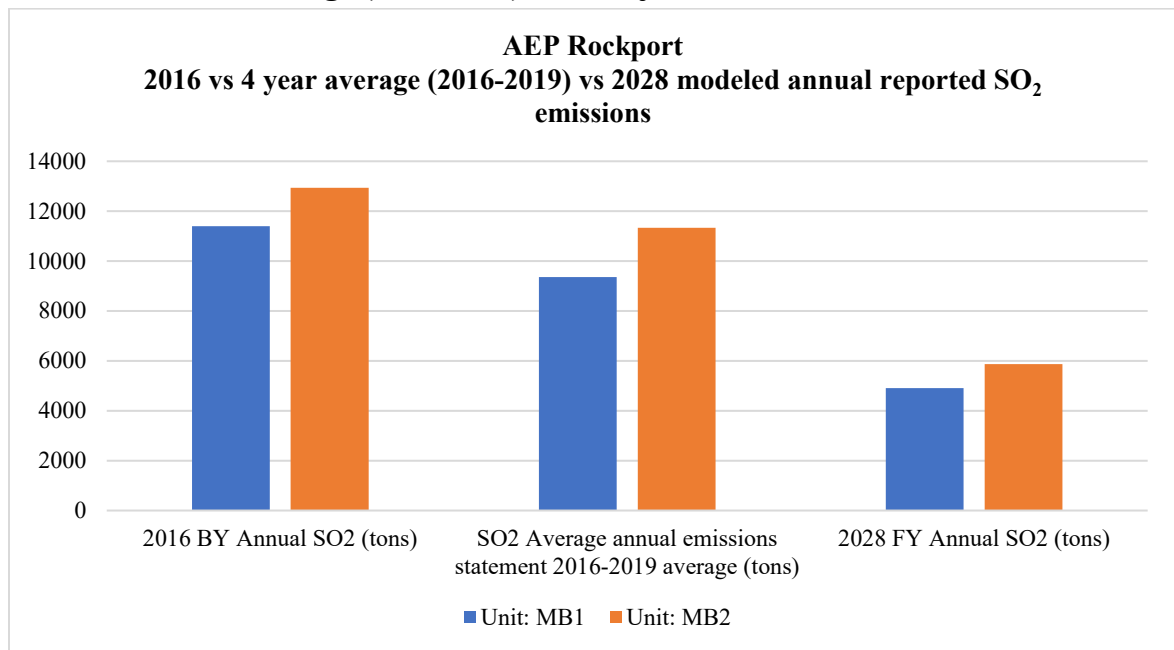
ORIS-ID	Steam Generator ID	Facility	BY-UF 2016 ERTAC	FY-UF 2028-ERTAC	Percentage Change in Utilization
6166	MB1	Rockport Plant	0.4619	0.4895	5.6%
6166	MB2	Rockport Plant	0.5534	0.5956	7.1%

Comparison of NO_x and SO₂ emissions by unit are shown below in Graphs 8-8 and 8-9. The analysis demonstrates the continued downward trend of emissions from 2016 to projected emissions for 2028 with NO_x and SO₂ emissions decreases at both Units MB1 and MB2.

Graph 8-8 Unit Comparison of AEP Rockport's NO_x Emissions - Actual 2016 and 4-Year Average (2016-2019) and Projected 2028



Graph 8-9 Unit Comparison of AEP Rockport's SO₂ Emissions - Actual 2016 and 4 - Year Average (2016-2019) and Projected 2028



8.6 AES Indiana Petersburg Generating Station

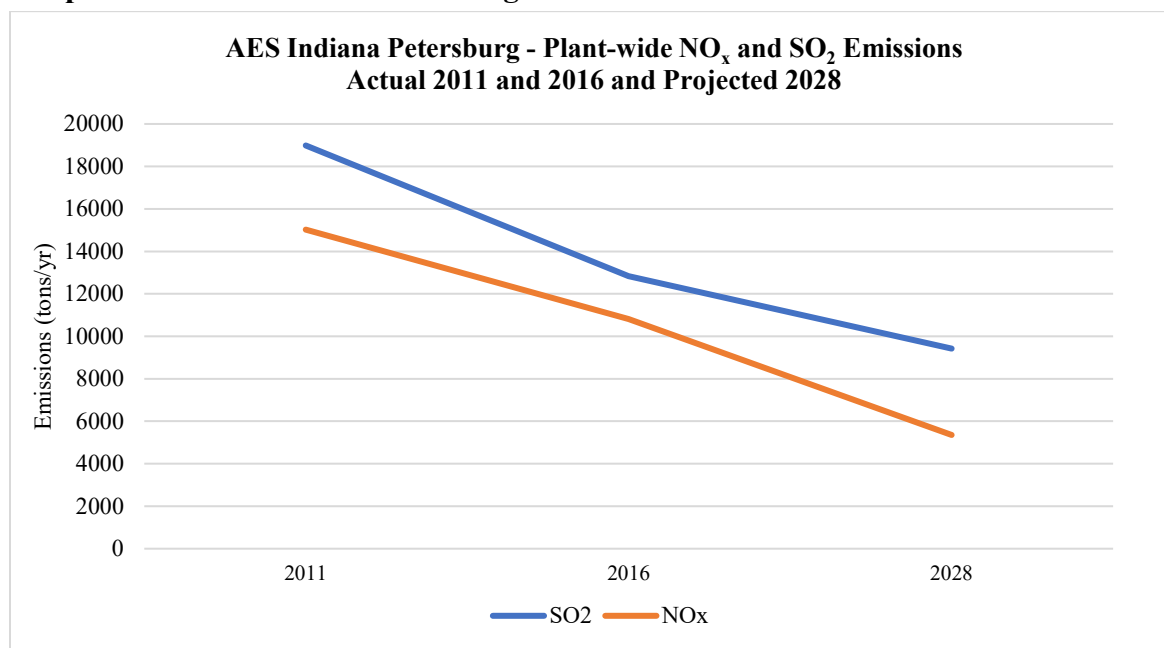
AES Indiana (AES) Petersburg Generating Station (Petersburg) is located in Pike County, in the southwestern portion of Indiana. It is a stationary electric utility generating station with a maximum generating capacity of 1,824 megawatts among four coal/No. 2 fuel oil fired boilers. Controls for these units include flue-gas desulfurization (FGD) scrubbers with SO₂ control efficiencies above 94% based on source estimates; low-NO_x burners (LNB) technology with activated carbon injection (ACI) technology on Unit 1, ACI technology with SCR system and LNB technology on Unit 2, ACI and SCR on Unit 3 and ACI and LNB as control for NO_x with control efficiencies on Units 3 and 4 above 70% based on source estimates (see Table 8 of Appendix F for source calculated control efficiencies).

Petersburg will retire Units 1 and 2 before 2028. AES Indiana made this decision based on the determination, in their 2019 IRP, that retiring those units was the “preferred low-cost option”. In addition, both units were identified as retiring in EPA’s 2020 National Electric Energy Demand System (NEEDS) update from CAMD. The source also confirmed the expected retirements of Units 1 and 2 with IDEM officials in November 2020. Finally, AES-Petersburg is now operating under a federal Consent Decree agreement with the United States and State of Indiana (Civil Action No. 3:20-cv-202-RYL-MPB, found at www.epa.gov/sites/default/files/2020-09/documents/indianapolispowerlight-cd.pdf) and will be subject to NO_x and SO₂ limitations for 2025 and 2026 as follows: operate the coal-fired Units 1 through 4 at the Petersburg Station so the Units combined do not emit SO₂ in excess of an annual tonnage limitation of 10,100 tons per year and operate the coal-fired

Units 1 through 4 at the Petersburg Station so the Units combined do not emit NO_x in excess of an annual tonnage limitation of 8,500 tons per year.

Petersburg's 2028 EGU NO_x emissions are projected to be reduced by 50.5% or 5,500 tons from 2016 emission levels and SO₂ emissions are estimated to be reduced by 26.6% or 3,400 tons from 2016 to 2028; primarily as a result of retirements at Units 1 & 2, shown in Graph 8-10.

Graph 8-10 AES Indiana Petersburg's NO_x and SO₂ Emissions Trends



The emissions projections for 2028 were determined by ERTAC which allocates power generation from units that will be retired before 2028 to other existing units. The overall emissions from AES Indiana - Petersburg will be lower as a result of the unit shutdowns but Units 3 and 4 emissions may be slightly higher than 2016 due to power demand and limited coal-fired power generating capacity with retirements of Units 1 and 2. For Petersburg, Units 3 and 4 will need to be utilized more in order to meet the electricity demands.

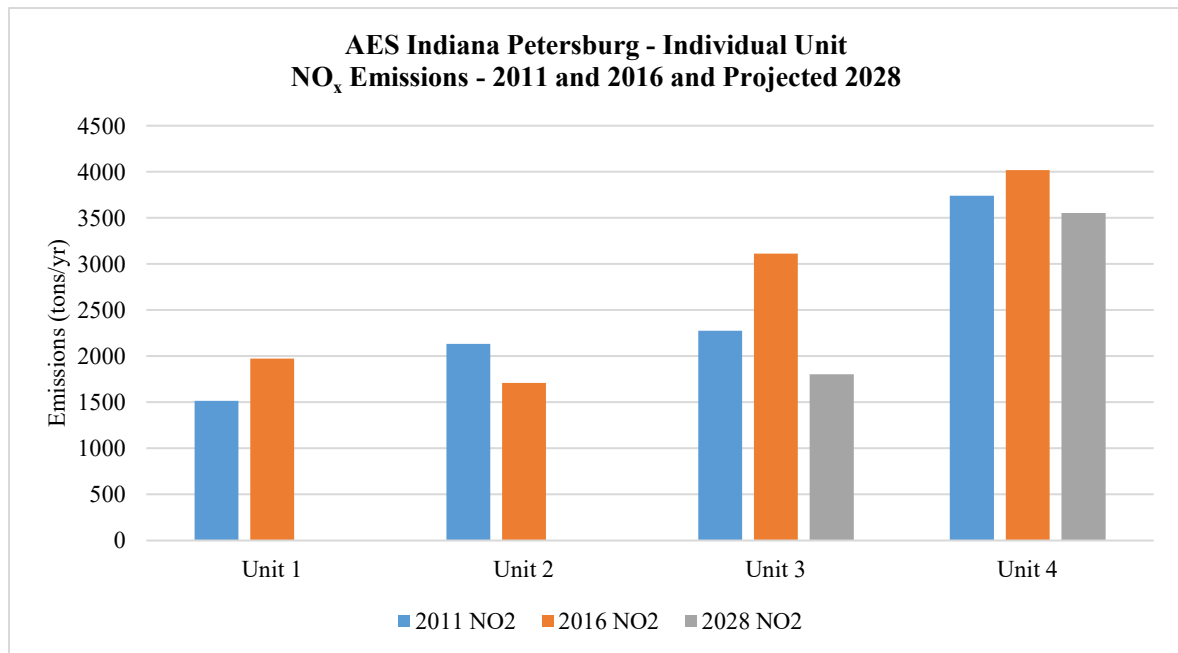
The projections for 2028 are determined by the ERTAC emissions model, which allocates power generation from units that will be retired before 2028. The overall emissions from each facility will be reduced because of the unit shutdowns but individual unit emissions may be slightly higher than their 2016 emissions due to power demand and limited coal-fired power generation capacity with retirements of other boilers. For Petersburg's future emissions projections, Units 3 and 4 are anticipated to be utilized more to meet the electricity demands for the area with the retirement of Units 1 and 2. Petersburg's unit utilization rates, both for base-year 2016 and future year 2028, are shown in Table 8-9.

Table 8-9 Petersburg Generating Station's 2016 and Projected 2028 Utilization Rates for Units 1-4

ORIS-ID	Unit ID	Facility	BY-UF 2016 ERTAC	FY-UF 2028 ERTAC	Percentage Change in Utilization
983	1	Petersburg Generating Station	0.8075	Retired	-100.0%
983	2	Petersburg Generating Station	0.5979	Retired	-100.0%
983	3	Petersburg Generating Station	0.6478	0.7282	11.0%
983	4	Petersburg Generating Station	0.5991	0.6493	7.7%

Graph 8-11 shows the unit-by-unit comparison of NO_x emissions at the Petersburg power plant. There are significant projected decreases in NO_x emissions with the retirement of Units 1 and 2 and modest NO_x emission reduction from Units 3 and 4 as observed from actual CAMD data for 2016 and ERTAC's projected 2028 emissions. These projected NO_x emission reductions, taken from the ERTAC emissions modeling, will occur due to the lower NO_x emission rates mandated by CSAPR and the reduced NO_x ozone season budget allocations for the facility in accordance with the Revised CRSPR Update Rule.

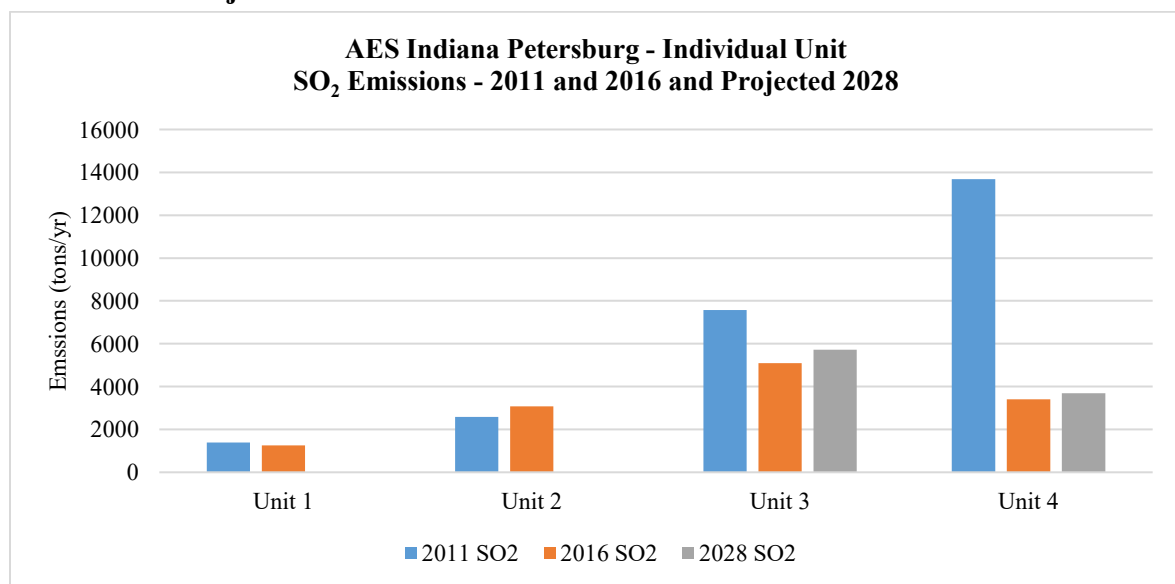
Graph 8-11 Unit Comparison of AES Indiana Petersburg's NO_x Emissions - Actual 2011 and 2016, Projected 2028



Graph 8-12 shows the unit-by-unit comparison of SO₂ emissions at the Petersburg power plant. With the retirements of both Units 1 and 2, overall SO₂ emissions decrease from actual CAMD data for 2011 and 2016 to ERTAC's projected 2028 emissions when taking all four units into account. Note the slight increase in projected emissions at Units 3 and 4 in 2028. This demonstrates the slight increase in utilization based on projected increased electricity demand in the area due to power generation as the ERTAC emissions model projected heat inputs for Units 2 and 4 in 2028 to be higher, therefore projected SO₂

emissions are expected to be higher. These increases equate to 12.4% for Unit 3 and 8.4% increase at Unit 4. These increases are a result of the retirements of Units 1 and 2 so overall SO₂ emissions are expected to be reduced by 26.6 %.

Graph 8-12 Unit Comparison of Petersburg’s SO₂ Emissions - Actual 2011 and 2016, Projected 2028

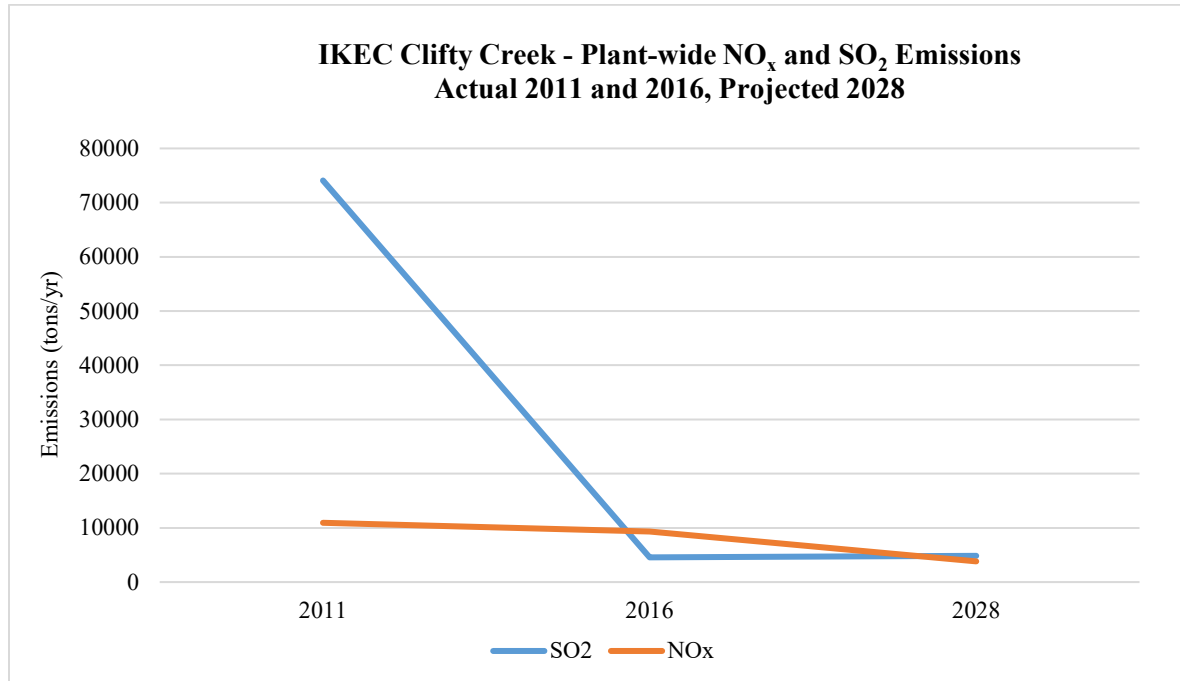


8.7 Indiana Kentucky Electric Corporation and the Ohio Valley Electrical Corporation’s Clifty Creek Station

The Indiana Kentucky Electric Corporation (IKEC) and the Ohio Valley Electrical Corporation’s Clifty Creek Station (Clifty Creek) is a 1,300 megawatts (MW) coal-fired power station located in Madison, Jefferson County. The Clifty Creek Station operates six wet-bottom pulverized coal-fired boilers, with each of its six generating units rated at 217.26 MW, for a total capacity of 1,303.56 MW. Controls for NO_x and SO₂ are as follows: Fluidized-Gas Desulfurization System and Overfire Air on all six units and Selective Catalytic Reduction on Units 1 through 5 (see Table 8 of Appendix F for source calculated control efficiencies).

Clifty Creek 2028 EGU NO_x emissions are projected to be reduced by 59% or 5,534 tons from 2016 emission levels and SO₂ emissions are expected to increase slightly, by 6% or 286 tons from 2016 to 2028. The ERTAC model projects small increases in utilization at the facility for all six units.

Graph 8-13 IKEC Clifty Creek NO_x and SO₂ Emission Trends



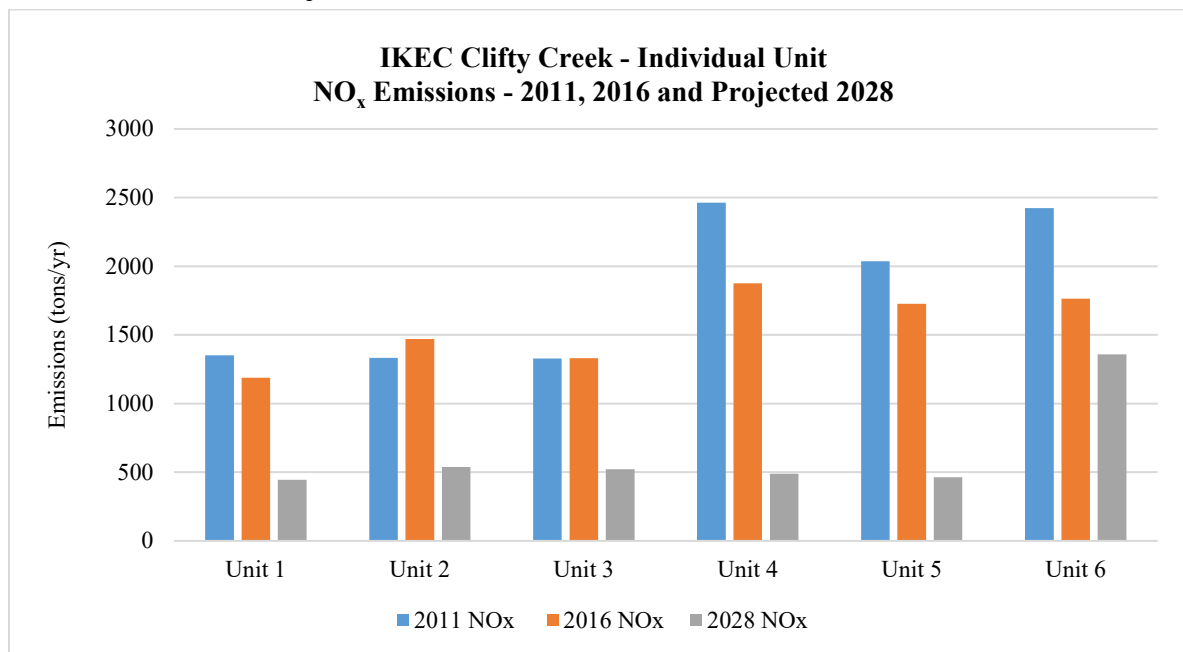
The projections for 2028 are determined by the ERTAC emissions model, which allocates power generation from units that will be retired before 2028. The overall emissions from each facility will be reduced because of the unit shutdowns but individual unit emissions may be slightly higher than their 2016 emissions due to power demand and limited coal-fired power generation capacity with retirements of other boilers. For Clifty Creek's future emissions projections, Units 1- 6 is anticipated to be utilized more to meet the electricity demands for the area. Clifty Creek's unit utilization rates, both for base-year 2016 and future year 2028, are shown in Table 8-10.

Table 8-10 Clifty Creek Generating Station's 2016 and Projected 2028 Utilization Rates for Units 1-6

ORIS-ID	Unit ID	Facility	BY-UF 2016 ERTAC	FY-UF 2028- ERTAC	Percentage Change in Utilization
983	1	Clifty Creek Generating Station	0.4689	0.4997	6.2%
983	2	Clifty Creek Generating Station	0.5439	0.5829	6.7%
983	3	Clifty Creek Generating Station	0.5354	0.5705	6.1%
983	4	Clifty Creek Generating Station	0.5094	0.5377	5.3%
983	5	Clifty Creek Generating Station	0.4861	0.5099	4.7%
983	6	Clifty Creek Generating Station	0.4607	0.4913	6.2%

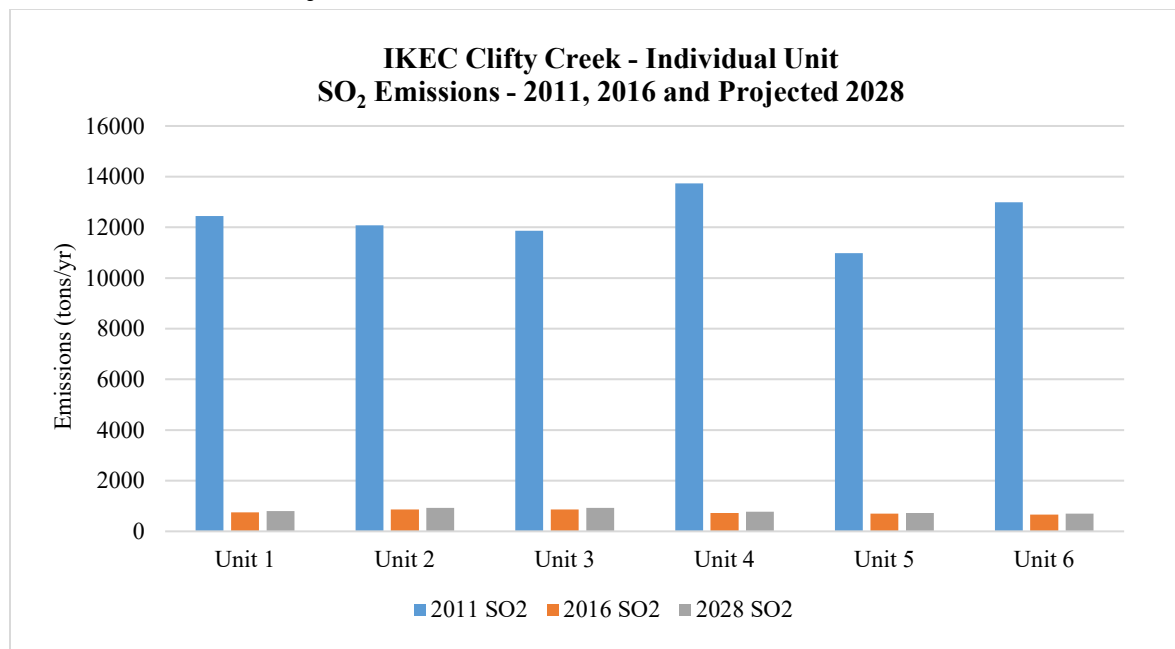
Graph 8-14 shows the unit-by-unit comparison of NO_x emissions at the Clifty Creek power plant. There is a significant projected decrease in NO_x emissions at each of the six units from actual CAMD data for 2011 and 2016 to projected 2028 emissions by ERTAC. These projected NO_x emission reductions, taken from the ERTAC emissions modeling, will occur due to the NO_x allocations for the facility mandated by the Revised CSAPR Update Rule.

Graph 8-14 Unit Comparison of IKEC Clifty Creek NO_x Emissions - Actual 2011 and 2016, Projected 2028



Graph 8-15 shows the unit-by-unit comparison of SO₂ emissions at the Clifty Creek power plant. Note the slight increase in projected emissions at each of the six units. This demonstrates the slight increase in utilization based on an increase in projected electricity demand in the area due to power plants in the area reducing their generation or retiring their coal-fired boilers. Heat input for each of the units are projected to increase from 2016 to 2028 as a result of the projected increase in utilization. The overall SO₂ emissions increase at Clifty Creek from 2016 to 2028 is projected to be 6%.

Graph 8-15 Unit Comparison of IKEC Clifty Creek SO₂ Emissions - Actual 2011 and 2016, Projected 2028

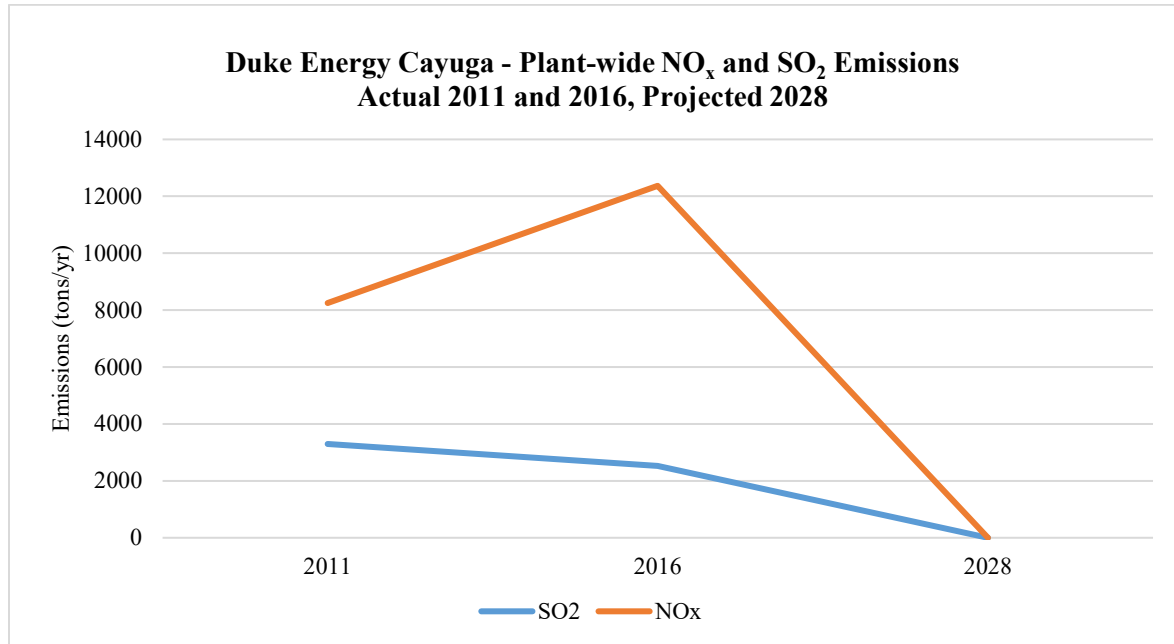


8.8 Duke Energy Indiana, LLC Cayuga Generating Station

Duke Energy Indiana, LLC (Duke Energy) - Cayuga Generating Station (Cayuga) is a three-unit generating facility built between 1970 and 1993 with a total generation capacity of 1,104 MW located in Vermillion County Indiana. Units 1 and 2 are dry bottom, pulverized coal-fired boilers that have been equipped with FGD scrubbers to reduce the station's sulfur dioxide emissions by approximately 95% (see Table 8 of Appendix F for source calculated control efficiencies). Both units also have a LNB and SCR to control NO_x emissions. Units 1 and 2 are expected to retire according to Duke's 2019 IRP resulting in 1108 MW of coal-fired retired power generation by 2028. Unit 4 is a NG and no. 2 fuel-oil-fired combustion turbine and does not have a retirement date as of the last IRP review.

Cayuga's 2028 EGU NO_x emissions are projected to be reduced by 100% or 12,369 tons from 2016 emission levels and SO₂ emissions are expected to be reduced by 100% or 2,520 tons from 2016 to 2028.

Graph 8-16 Duke Energy Cayuga NO_x and SO₂ Emissions Trends



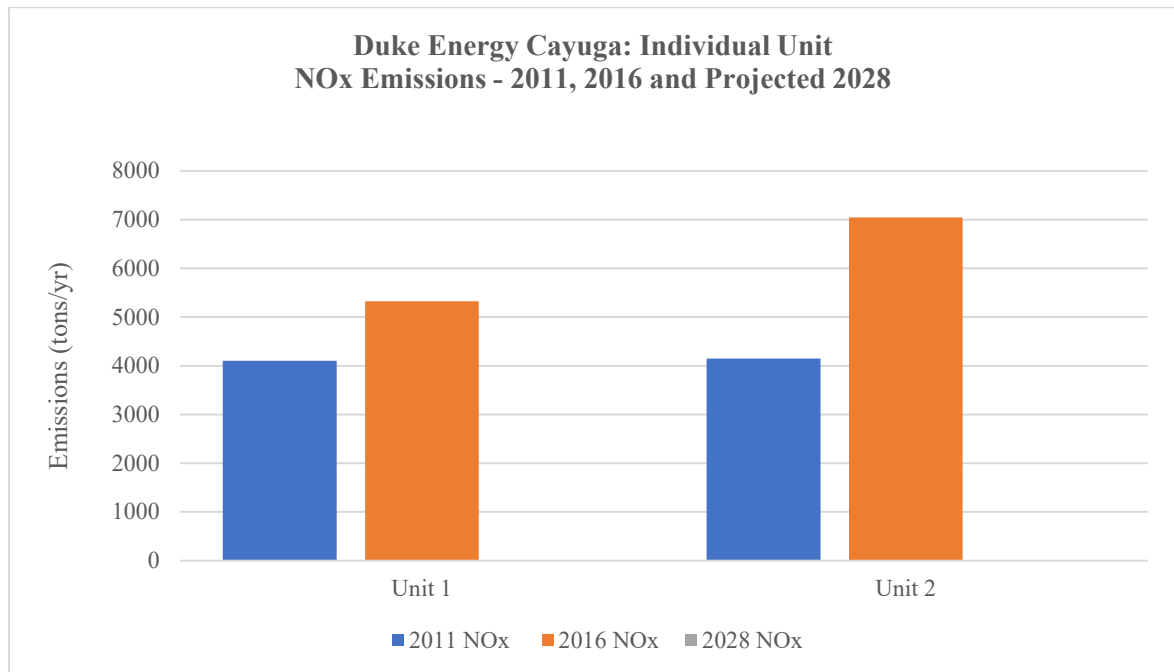
The projections for 2028 are determined by the ERTAC emissions model, which allocates power generation from units that will be retired before 2028. The overall emissions from each facility will be reduced because of the unit shutdowns but individual unit emissions may be slightly higher than their 2016 emissions due to power demand and limited power generation capacity with retirements of other boilers. For Cayuga's future emissions projections, Unit 4 may be utilized more to meet the electricity demands without Units 1 and 2. Cayuga's unit utilization rates, both for base-year 2016 and future year 2028, are shown in Table 8-11.

Table 8-11 Cayuga Power Generating Station's 2016 and Projected 2028 Utilization Rates for Units 1, 2 and 4

ORIS-ID	Unit ID	Facility	BY-UF 2016 ERTAC	FY-UF 2028- ERTAC	Percentage Change in Utilization
1001	1	Cayuga Generating Station	0.5365	Retired	-100.0%
1001	2	Cayuga Generating Station	0.8109	Retired	-100.0%
1001	4	Cayuga Generating Station	0.0005	0.0017	68.6%

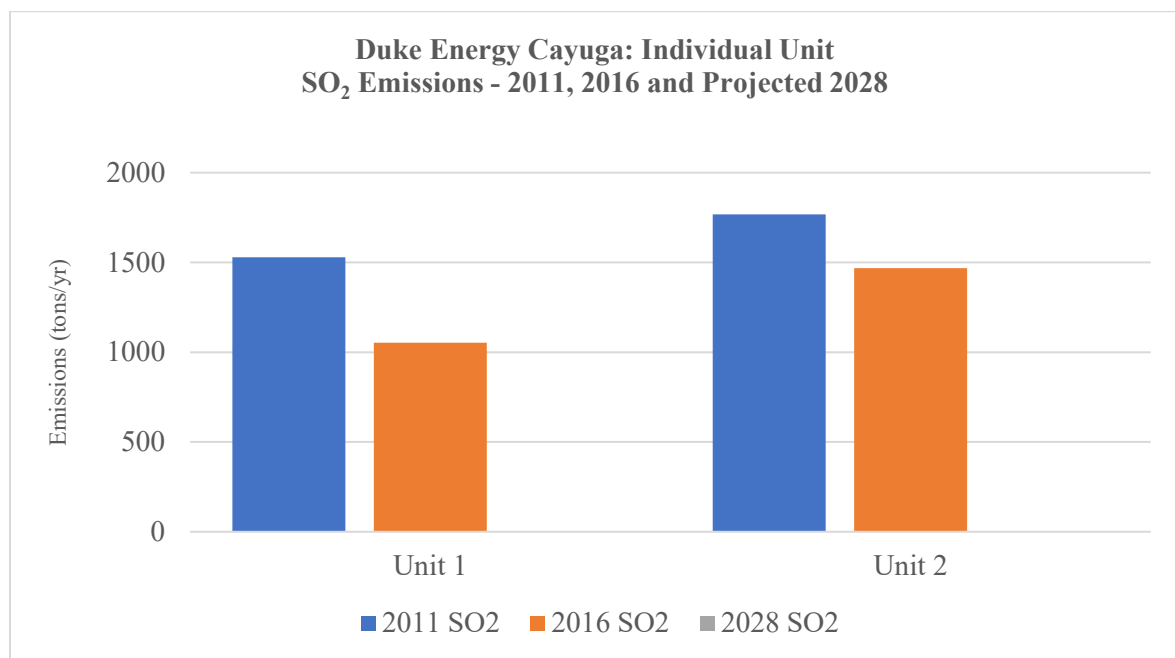
Graph 8-17 shows the unit-by-unit comparison of NO_x emissions at the Cayuga power plant. With the retirements of both Units 1 and 2, NO_x emissions at both units decrease from actual CAMD data for 2011 and 2016 to ERTAC's projected 2028 emissions of zero. Unit 4 is not included in the chart because its base year and future year utilization is very low with total NO_x emissions less than 1 ton per year.

Graph 8-17 Unit Comparison of Duke Energy Cayuga NO_x Emissions - Actual 2011 and 2016, Projected 2028



Graph 8-18 shows the unit-by-unit comparison of SO₂ emissions at the Cayuga power plant. With the retirements of both Units 1 and 2, SO₂ emissions at both units decrease from actual CAMD data for 2011 and 2016 to ERTAC's projected 2028 emissions of zero. Unit 4 is not included in the chart because its base year and future year utilization is very low with total SO₂ emissions less than 1 ton per year.

Graph 8-18 Unit Comparison of Duke Energy Cayuga SO₂ Emissions - Actual 2011 and 2016, Projected 2028

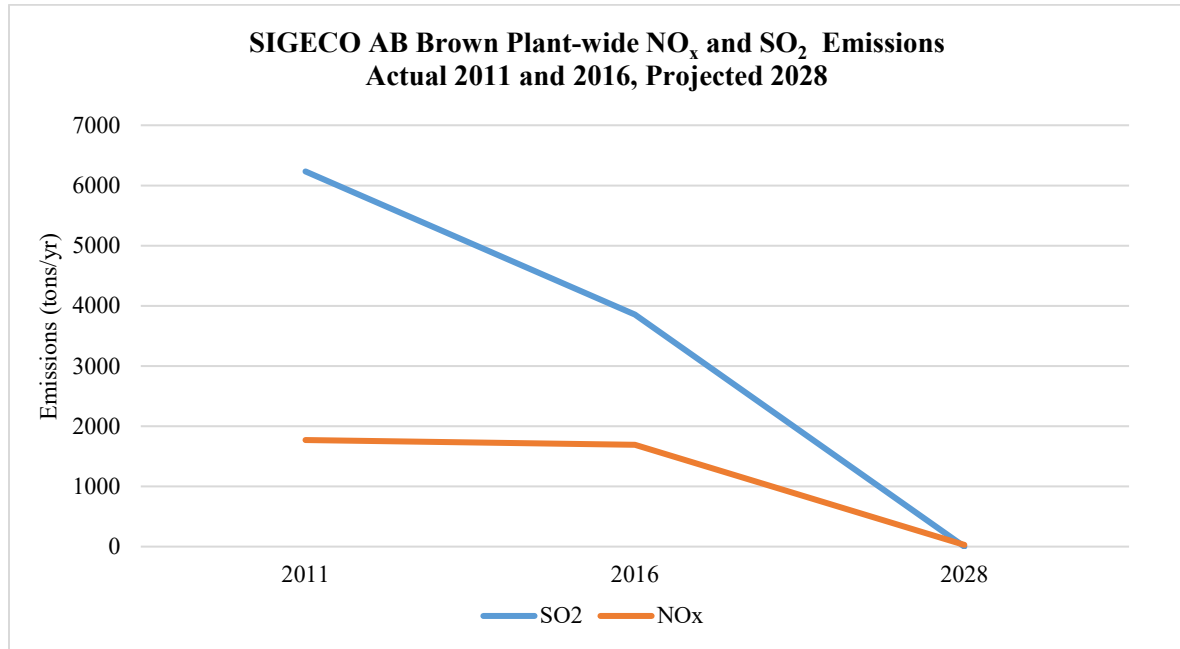


8.9 Southern Indiana Gas and Electric Company AB Brown Generating Station

Southern Indiana Gas and Electric Company (SIGECO) AB Brown Generating Station (AB Brown) is a four-unit, 700-MW power generating facility located near Mount Vernon, Posey County, Indiana. The two, dry bottom, pulverized coal-fired boilers (Units 1 and 2) have a name-plate capacity of 265.2 MW, commissioned from 1979 to 1986. Unit 1 controls include dual alkali FGD system for control of SO₂, with low-NO_x combustion (low-excess air and LNB and SCR system for control of NO_x. Unit 2 controls include a dual alkali FGD system for control of SO₂, with low-NO_x combustion (low-excess air and LNB and SCR system for control of NO_x (see Table 8 of Appendix F for source calculated control efficiencies). Units 1 and 2 are set to retire in 2023 per the 2019-2020 IRP and will remove 530 MW of coal fired generation off the power grid. There are also two simple-cycle, NG-fired combustion turbines (Units ABB 3 and ABB4) that have 88.2 MW of nameplate capacity each.

AB Brown's 2028 EGU NO_x emissions are projected to be reduced by 98% or 1,665 tons from 2016 emission levels and SO₂ emissions are expected to be reduced by 100% or 3,854 tons from 2016 to 2028.

Graph 8-19 SIGECO AB Brown NO_x and SO₂ Emissions Trends



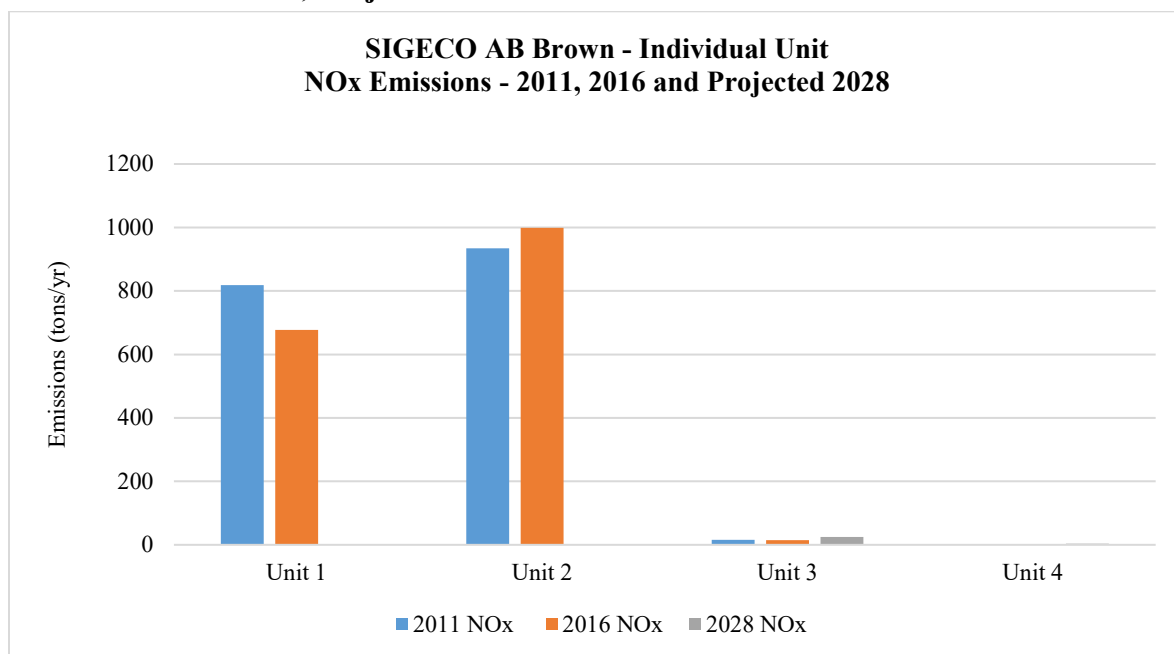
The projections for 2028 are determined by the ERTAC emissions model, which allocates power generation from units that will be retired before 2028. The overall emissions from each facility will be reduced because of the unit shutdowns but individual unit emissions may be slightly higher than their 2016 emissions due to power demand and limited power generation capacity with retirements of other boilers. For AB Brown's future emissions projections, Units 1 and 2 megawatts are being replaced by renewables and NG-fired combustion turbines. The renewables filing was recently submitted. Units 3 and 4 will be utilized more to meet the electricity demands without Unit 1 and 2. AB Brown's unit utilization rates, both for base-year 2016 and future year 2028, are shown in Table 8-12.

Table 8-12 AB Brown Generation Station's 2016 and Projected 2028 Utilization Rates for Units 1-5

ORIS-ID	Unit ID	Facility	BY-UF 2016 ERTAC	FY-UF 2028- ERTAC	Percentage Change in Utilization
6137	1	AB Brown Generating Station	0.2997	Retired	-100.0%
6137	2	AB Brown Generating Station	0.3819	Retired	-100.0%
6137	3	AB Brown Generating Station	0.0150	0.0249	39.7%
6137	4	AB Brown Generating Station	0.0145	0.0236	38.8%

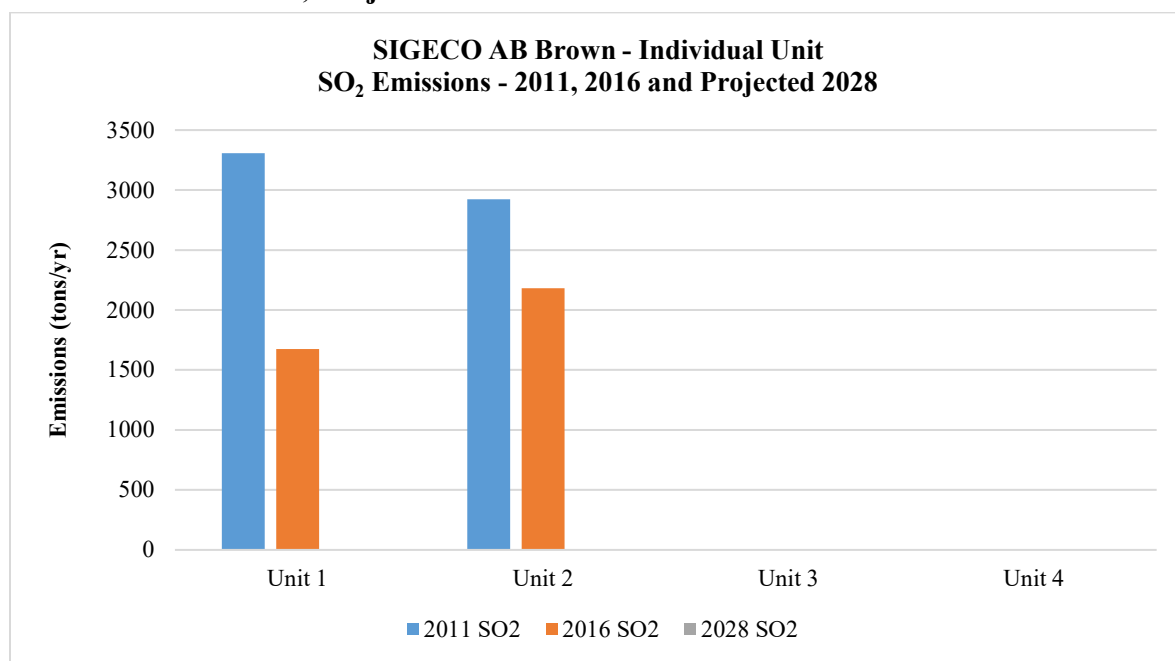
Graph 8-20 shows the unit-by-unit comparison of NO_x emissions at the AB Brown power plant. With the retirements of both Units 1 and 2, NO_x emissions at both units decrease from actual CAMD data for 2011 and 2016 to projected 2028 emissions by ERTAC of zero. Units ABB3 and ABB4's base year and future year utilization are low so projected NO_x emissions for 2028 will be very low.

Graph 8-20 Unit Comparison of SIGECO AB Brown NO_x Emissions - Actual 2011 and 2016, Projected 2028



Graph 8-21 shows the unit-by-unit comparison of SO₂ emissions at the AB Brown power plant. With the retirements of both Units 1 and 2, SO₂ emissions at both units decrease from actual CAMD data for 2011 and 2016 to projected emissions by ERTAC in 2028 of zero. The NG-fired combustion turbines, Units ABB3 and ABB4's base year and future year utilization are low so projected SO₂ emissions for 2028 will be very low.

Graph 8-21 Unit Comparison of SIGECO AB Brown SO₂ Emissions - Actual 2011 and 2016, Projected 2028

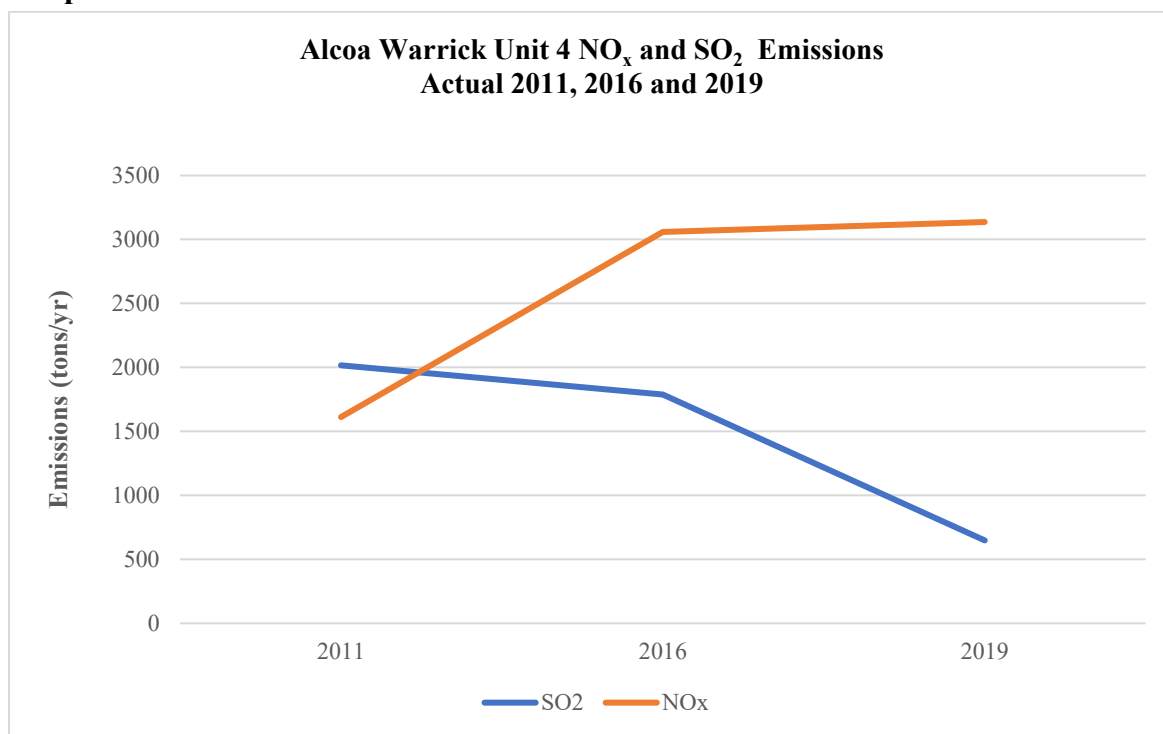


8.10 Alcoa Power Generating Inc Warrick Power Plant

Alcoa Power Generating Inc - Warrick Power Plant (Alcoa) owns three of the four generating stations at the Warrick facility, located near Newburgh, Warrick County, Indiana. These units were placed into service in the early 1960s. The largest unit, known as Unit 4, is a dry bottom, pulverized coal-fired boiler with capacity of 323-MW jointly owned by Alcoa and Vectren and is characterized as an EGU. Emission controls include LNB and a SCR system for NO_x and a wet FGD scrubber for SO₂ controls (see Table 8 of Appendix F for source calculated control efficiencies).

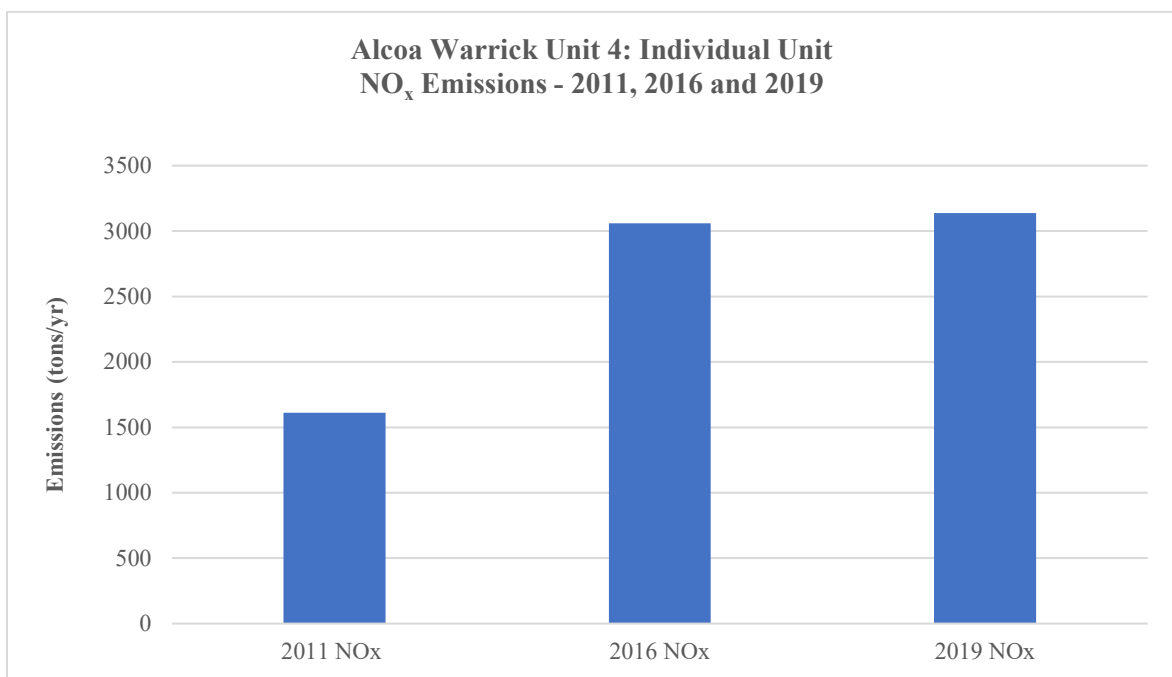
According to the 2019-2020 Vectren IRP, Alcoa and Vectren would exit their agreement to purchase power in 2023 from Alcoa Unit 4. Therefore, this unit was not modeled as an EGU and was not included in the ERTAC future year emissions projections and was not modeled by LADCO. After modeling was concluded, the agency learned that the unit would continue operating as an EGU after 2023 with similar emissions. This unit will be added back to the next round of ERTAC modeling as a non-EGU to correct this issue. This modeling will be completed in October of 2021, thus allowing IDEM to evaluate the projected NO_x and SO₂ emissions in Indiana's RH progress report, due in 2025.

Graph 8-22 Alcoa Warrick Unit 4 NO_x and SO₂ Emissions Trends



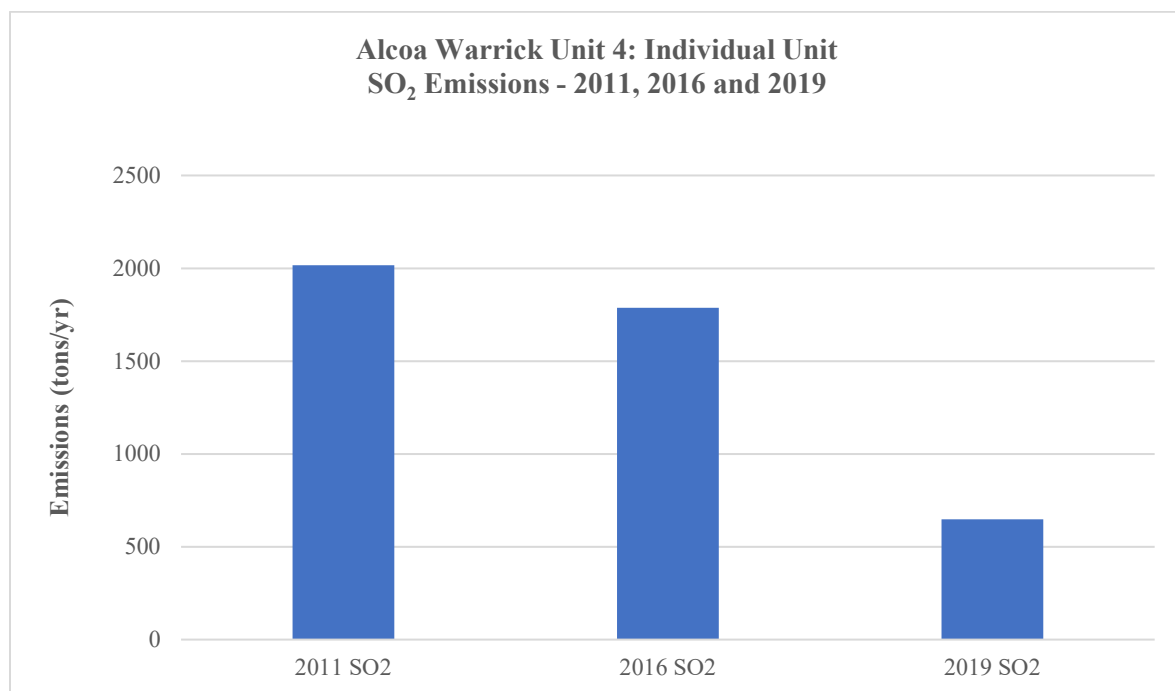
Graph 8-23 shows the unit-by-unit comparison of NO_x emissions at the Alcoa power plant. With the originally presumed retirement of Unit 4, NO_x emissions were modeled to decrease from actual CAMD reported emissions for 2011 and 2016 to projected 2028 emissions by ERTAC of zero but in fact they should be close to the 2016 reported levels. In fact, review of the actual NO_x emissions from Alcoa, as shown in Appendix E, under the “EGUs 2007-2019 NO_x Emissions” tab, actual NO_x emissions at Unit 4 have been steady and close to the 2016 reported level of just over 3,000 tons per year. This unit’s projected NO_x emissions will be evaluated in Indiana’s RH Five-Year Progress Report in 2025.

Graph 8-23 Unit Comparison of Alcoa Warrick NO_x Emissions - Actual 2011, 2016 and 2019



Graph 8-24 shows the unit-by-unit comparison of SO₂ emissions at the Alcoa power plant. With the originally presumed retirement of Unit 4, SO₂ emissions were modeled to decrease from actual CAMD reported emissions for 2011 and 2016 to projected 2028 emissions by ERTAC of zero but in fact they should be close to the 2016 reported levels. In fact, review of the actual SO₂ emissions from Alcoa, as shown in Appendix E, under the “EGUs 2007-2019 SO₂ Emissions” tab, actual SO₂ emissions have steadily declined at Unit 4 from 1,787 tons of SO₂ in 2016 to 648 tons of SO₂ in 2019. As mentioned, this unit’s SO₂ emissions will be evaluated in Indiana’s RH Five-Year Progress Report in 2025.

Graph 8-24 Unit Comparison of Alcoa Warrick SO₂ Emissions - Actual 2011, 2016 and 2019



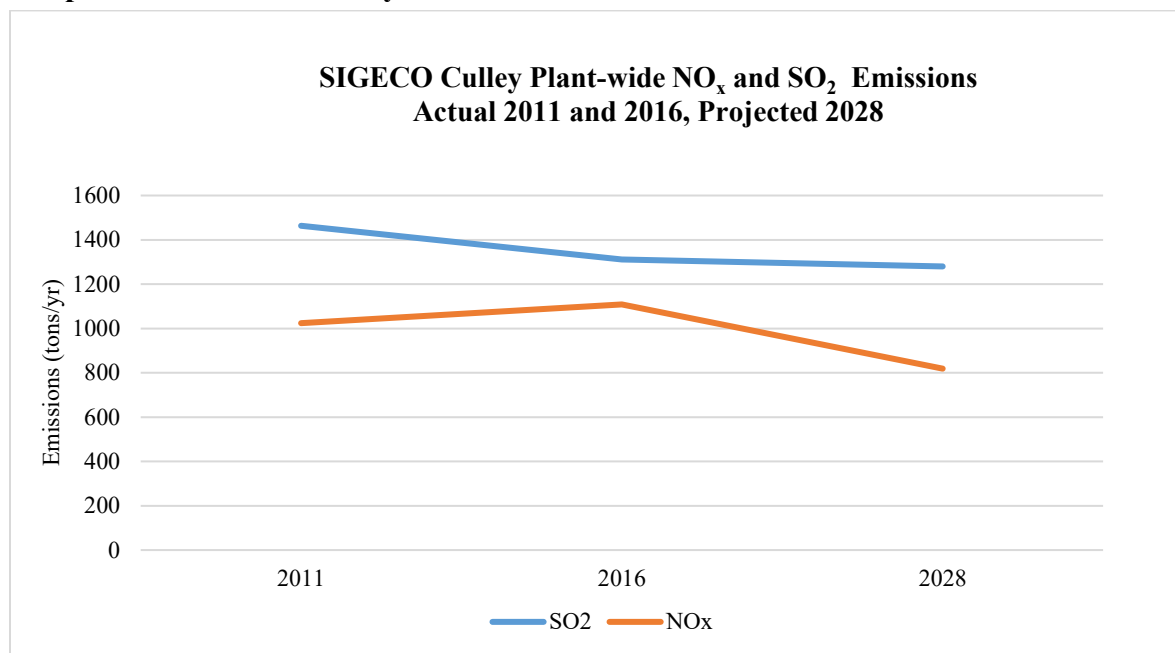
8.11 Southern Indiana Gas and Electric Company F. B. Culley Generating Station

Southern Indiana Gas and Electric Company (SIGECO) F. B. Culley Generating Station (Culley) is a coal-fired power plant located southeast of Newburgh in Warrick County, Indiana. Culley has two coal/NG fired boilers, Unit 2 has a generation capacity of 90 MW and Unit 3 has a generation capacity of 270 MW. It is expected that Unit 2 will retire in 2023 and remove 90 MW of coal-fired power generation from the grid. This information was obtained from the Vectren 2019-2020 IRP. Emission controls include LNB for NO_x control and FGD system for SO₂ controls on Unit 2. Unit 3 has LNB and SCR for NO_x reduction and shares the FGD system for SO₂ controls with Unit 2 (see Table 8 of Appendix F for source calculated control efficiencies).

Culley’s 2028 EGU NO_x emissions are projected to be reduced by 26% or 290 tons from 2016 emission levels and SO₂ emissions are expected to be reduced by 2% or 31 tons from 2016 to 2028. While overall emissions at the facility are down between 2016 and 2028,

Unit 3 may have increased utilization and be required to operate more in order to meet the demand for additional power generation as a result of the retirement of Unit 2.

Graph 8-25 SIGECO Culley NO_x and SO₂ Emissions Trends



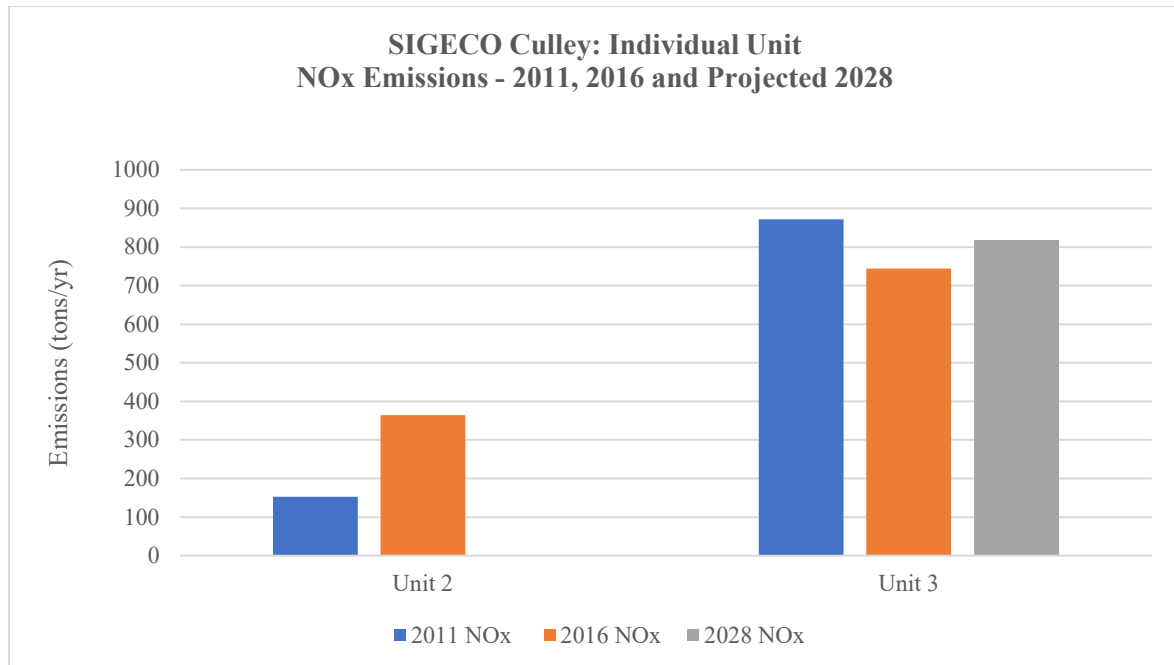
The projections for 2028 are determined by the ERTAC emissions model, which allocates power generation from units that will be retired before 2028. The overall emissions from each facility will be reduced because of the unit shutdowns but individual unit emissions may be slightly higher than their 2016 emissions due to power demand and limited power generation capacity with retirements of other boilers. For Culley's future emissions projections, Unit 2 coal-fired power generation is being replaced with renewables and NG-fired combustion turbines. The renewables filing was recently submitted with the Indiana Utility Regulatory Commission. Meanwhile, Unit 3 may be utilized more to meet the electricity demands with the retirement of Unit 2. Culley's unit utilization rates, both for base-year 2016 and future year 2028, are shown in Table 8-13.

Table 8-13 Culley Generating Station's 2016 and Projected 2028 Utilization Rates for Units 2 and 3

ORIS-ID	Unit ID	Facility	BY-UF 2016 ERTAC	FY-UF 2028- ERTAC	Percentage Change in Utilization
1012	2	F B Culley Generating Station	0.0999	Retired	-100.00%
1012	3	F B Culley Generating Station	0.3745	0.4114	11.93%

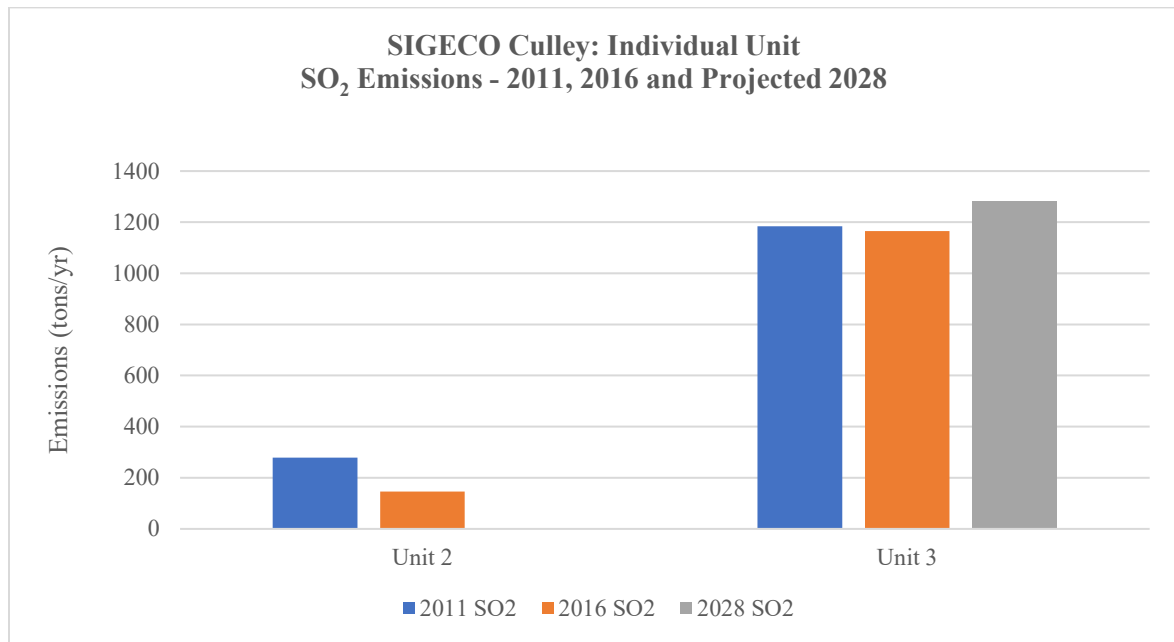
Graph 8-26 shows the unit-by-unit comparison of NO_x emissions at the Culley power plant. Note the slight increase in projected emissions at Unit 3. This demonstrates the slight increase in utilization based on projected electricity demand in the area due to the retirement of Unit 2 as heat input in 2028 for Unit 3 is also projected to be higher. The overall NO_x emissions decrease at Culley from 2016 to 2028 is projected to be 26%.

Graph 8-26 Unit Comparison of SIGECO Culley NO_x Emissions - Actual 2011 and 2016, Projected 2028



Graph 8-27 shows the unit-by-unit comparison of SO₂ emissions at the Culley power plant. Note the slight increase in projected emissions at Unit 3. This demonstrates the slight increase in utilization based on projected electricity demand in the area due to the retirement of Unit 2. The overall SO₂ emissions decrease at Culley from 2016 to 2028 is projected to be 2%.

Graph 8-27 Unit Comparison of SIGECO Culley SO₂ Emissions - Actual 2011 and 2016, Projected 2028

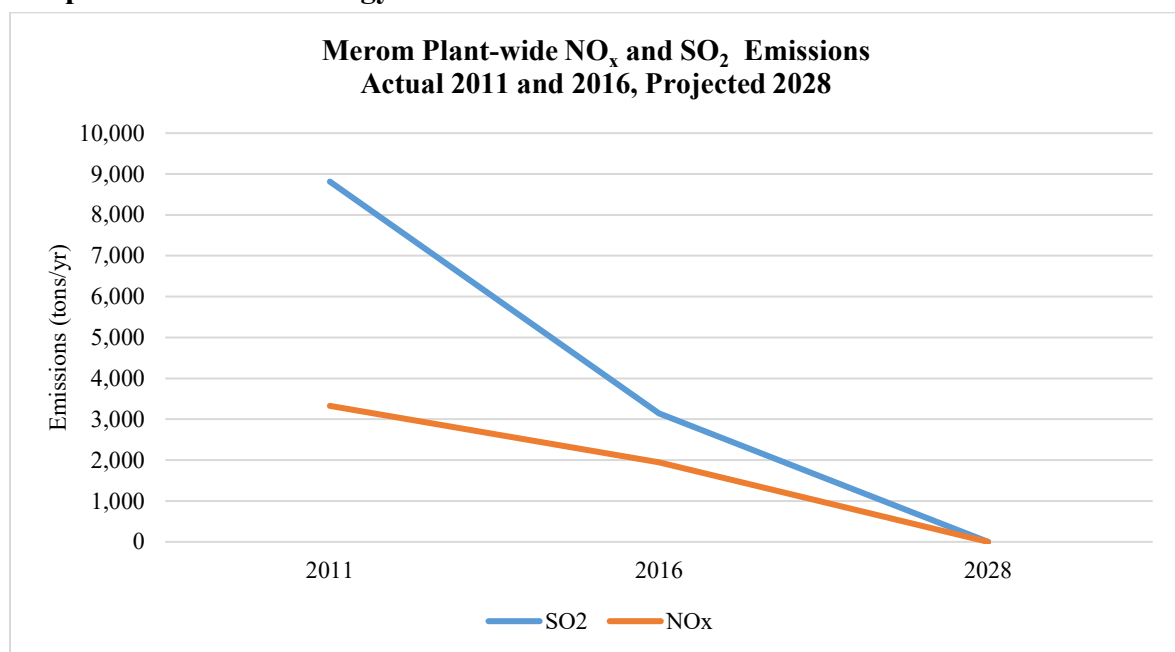


8.12 Hoosier Energy REC Inc Merom Generating Station

Hoosier Energy REC Inc (Hoosier Energy) - Merom Generating Station (Merom) is a two-unit, 1080 MW rated coal-fired power plant located near Merom, Indiana in Sullivan County, Indiana. The two pulverized coal-fired dry bottom boilers (Units 1SG1 and 2SG1) are owned by Hoosier Energy REC Inc, a Touchstone Energy cooperative. Emission controls for both units include FGD, Wet Scrubber System and SCR (see Table 8 of Appendix F for source calculated control efficiencies). The plant has been in operation since 1982 and is expected to retire both units in 2023 according to the following; December 2020 NEEDsv620 update from CAMD, also the IPMv5.15 CSAPR update has the units retired by 2024, as well as the Hoosier Energy 20-year plan and the retirements were included in the Merom November 2020 IRP.

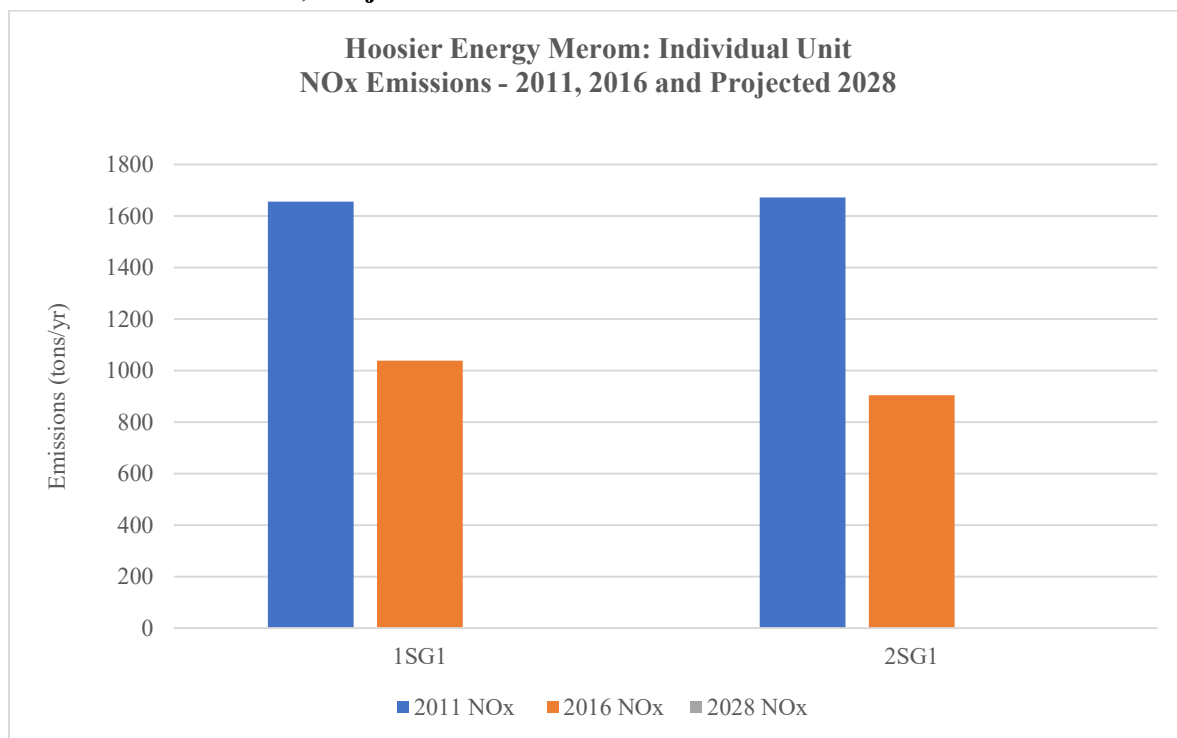
Merom's 2028 EGU NO_x emissions are projected to be reduced by 1,942 tons from 2016 emission levels and SO₂ emissions are expected to be reduced by 3,143 tons from 2016 to 2028.

Graph 8-28 Hoosier Energy Merom NO_x and SO₂ Emissions Trends



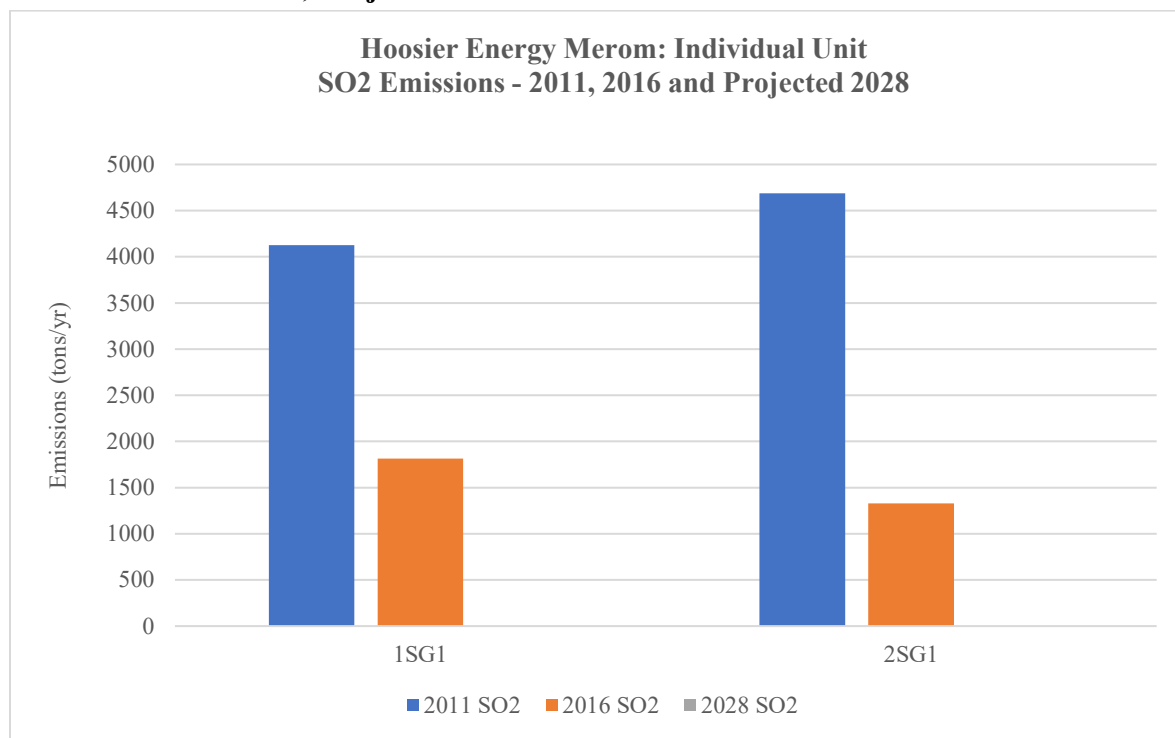
Graph 8-29 shows the unit-by-unit comparison of NO_x emissions at the Merom power plant. With the retirements of both Units 1SG1 and 2SG1, NO_x emissions at both units decrease from actual CAMD data for 2011 and 2016 to ERTAC's projected 2028 emissions of zero.

Graph 8-29 Unit Comparison of Hoosier Energy Merom NO_x Emissions - Actual 2011 and 2016, Projected 2028



Graph 8-30 shows the unit-by-unit comparison of SO₂ emissions at the Merom power plant. With the retirements of both Units 1SG1 and 2SG1, SO₂ emissions at both units decrease from actual CAMD data for 2011 and 2016 to ERTAC's projected 2028 emissions of zero.

Graph 8-30 Unit Comparison of Hoosier Energy Merom SO₂ Emissions - Actual 2011 and 2016, Projected 2028

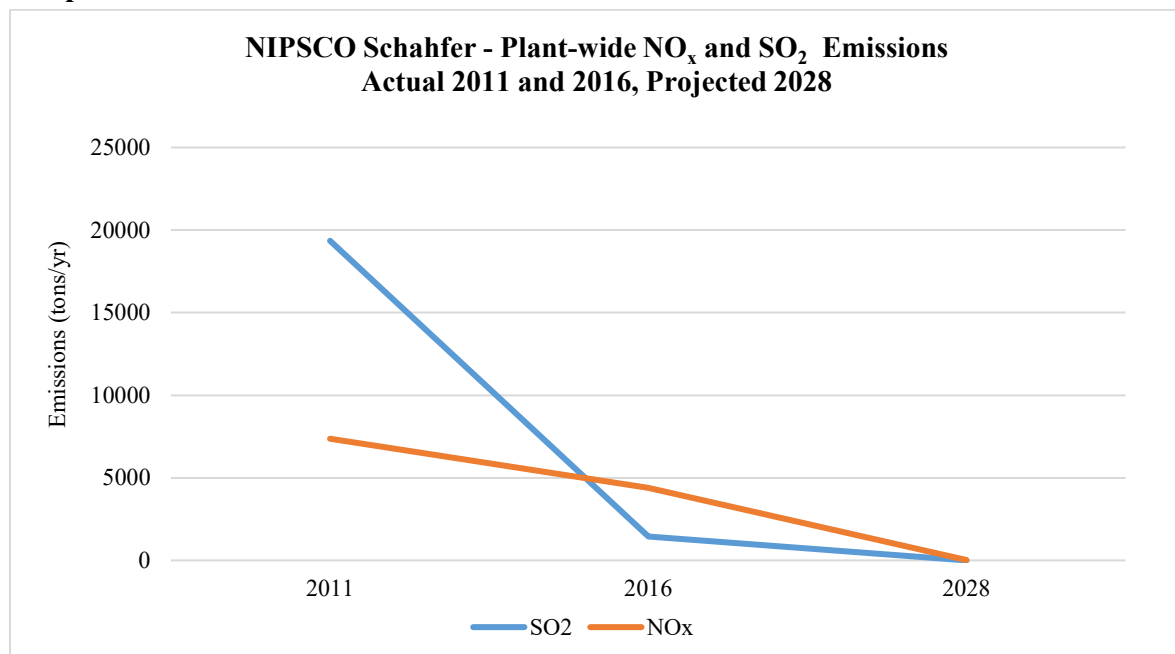


8.13 Northern Indiana Public Service Company, LLC R.M. Schahfer Generating Station

The Northern Indiana Public Service Company, LLC (NIPSCO) R.M. Schahfer Generating Station (Schahfer) is located near Wheatfield in Jasper County, Indiana. There are four dry bottom pulverized coal-fired boilers (Units 14, 15, 17 and 18) and two NG-fired combustion turbines (Units 16A and 16B). Emission controls for Unit 14 include selective SCR system, a reagent injection system, a flue gas desulfurization system, Unit 15 has selective non-catalytic reduction (SNCR) system, a reagent injection system, a flue gas desulfurization system for emission controls (see Table 8 of Appendix F for source calculated control efficiencies). Unit 17 and 18 each rely on LNB and limestone-based flue gas desulfurization system for emission controls. Retirement of 1700 MW in coal-fired power generation from Units 14, 15, 17 & 18 are expected based on the 2018 IRP with all four units retired by 2023 in the modeling analysis. Recent updates indicate that units 14 and 15 will retire by the end of 2021. These retirements are included in the CAMD December 2020 NEEDsv620 update. Units 16A and 16B have water injection as needed for NO_x control and are projected to remain in operation.

R.M. Schahfer's 2028 EGU NO_x emissions are projected to be reduced by 4,373 tons from 2016 emission levels and SO₂ emissions are expected to be reduced by 1,440 tons from 2016 to 2028. This will result in a 99% reduction in emission from the facility if the two simple cycle units remain.

Graph 8-31 NIPSCO Schahfer NO_x and SO₂ Emissions Trends



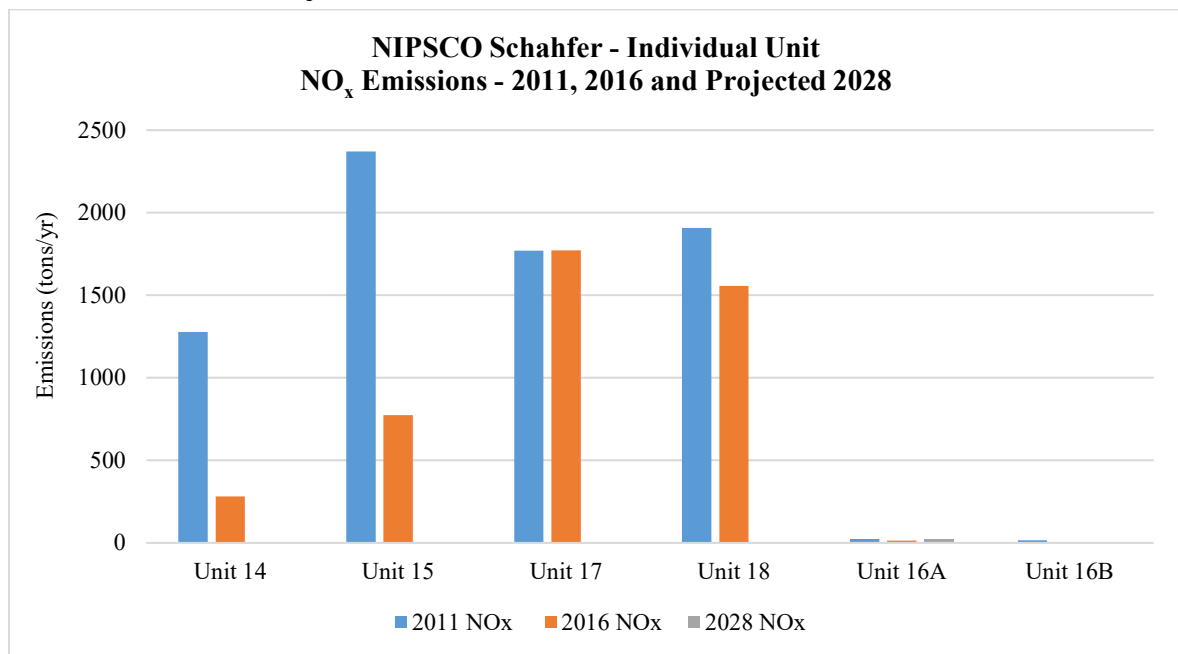
The projections for 2028 are determined by the ERTAC emissions model, which allocates power generation from units that will be retired before 2028. The overall emissions from each facility will be reduced because of the unit shutdowns but individual unit emissions may be slightly higher than their 2016 emissions due to power demand and limited coal-fired power generation capacity with retirements of other boilers. For Schahfer's future emissions projections, the NG-fired combustion turbines, Units 16A and 16B, may be utilized more to meet the electricity demands without Units 14, 15, 17 and 18. Schahfer's unit utilization rates, both for base-year 2016 and future year 2028, are shown in Table 8-31.

Table 8-14 Schahfer Generating Station's 2016 and Projected 2028 Utilization Rates for Units 14, 15, 17, 18, 16A, and 16B

ORIS-ID	Unit ID	Facility	BY-UF 2016 ERTAC	FY-UF 2028- ERTAC	Percentage Change in Utilization
6085	14	Schahfer Generating Station	0.1405	Retired	-100.0%
6085	15	Schahfer Generating Station	0.2864	Retired	-100.0%
6085	17	Schahfer Generating Station	0.5187	Retired	-100.0%
6085	18	Schahfer Generating Station	0.4539	Retired	-100.0%
6085	16A	Schahfer Generating Station	0.0077	0.0132	42.1%
6085	16B	Schahfer Generating Station	Not reported	0.0004	100.0%

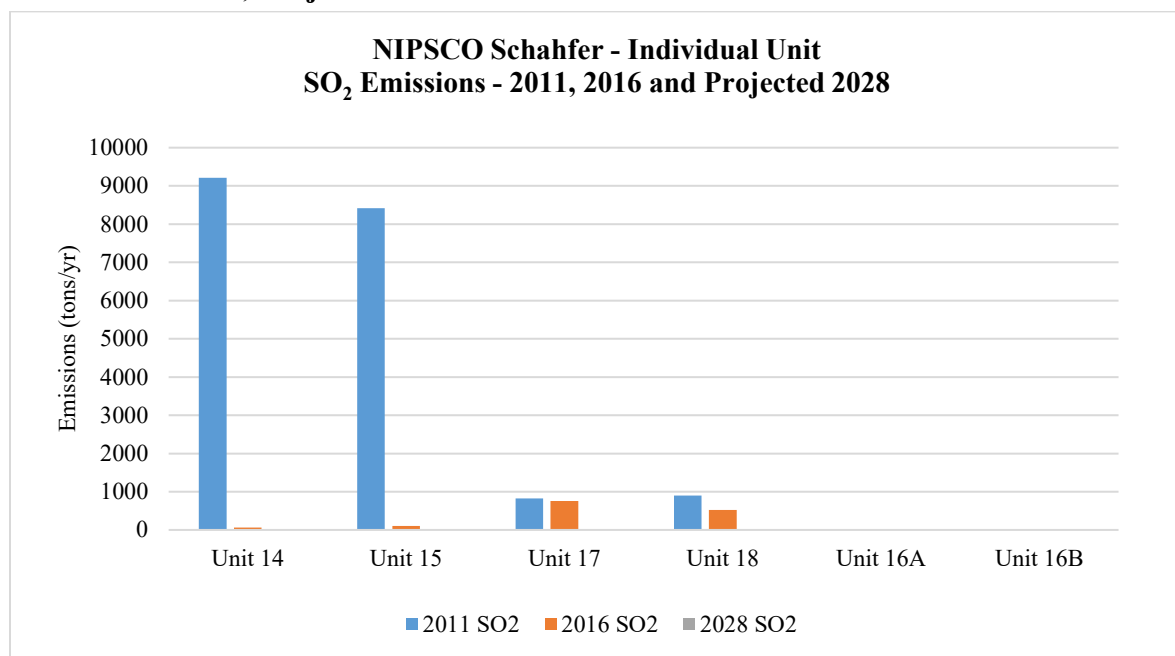
Graph 8-32 shows the unit-by-unit comparison of NO_x emissions at the Schahfer power plant. With the retirements of Units 14, 15, 17, and 18, NO_x emissions at all these units decrease from actual CAMD data for 2011 and 2016 to ERTAC's projected emissions in 2028 of zero. The NG-fired combustion turbines, Units 16A and 16B's base year and future year utilization are low so projected NO_x emissions for 2028 will be very low.

Graph 8-32 Unit Comparison of NIPSCO Schahfer NO_x Emissions - Actual 2011 and 2016, Projected 2028



Graph 8-33 shows the unit-by-unit comparison of SO₂ emissions at the Schahfer power plant. With the retirements of Units 14, 15, 17 and 18, SO₂ emissions at all these units decrease from actual CAMD data for 2011 and 2016 to ERTAC's projected emissions in 2028 of zero. The NG-fired combustion turbines, Units 16A and 16B's base year and future year utilization are low so projected SO₂ emissions for 2028 will be very low.

Graph 8-33 Unit Comparison of NIPSCO Schahfer SO₂ Emissions - Actual 2011 and 2016, Projected 2028

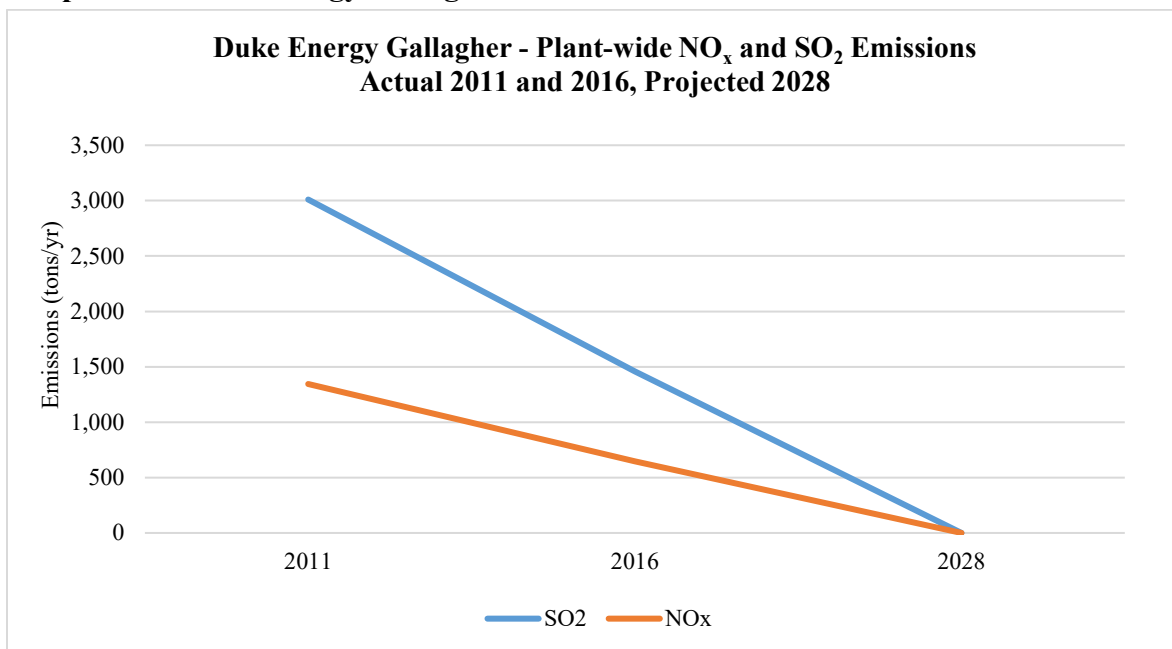


8.14 Duke Energy Indiana, LLC Gallagher Generating Station

The Duke Energy Indiana, LLC - Gallagher Generating Station (Gallagher) is currently a two-unit coal-fired generating facility located in Floyd County, Indiana. There were initially four units which were dry bottom, pulverized coal-fired boilers. Unit 2 began operating in 1958; Unit 1 in 1959; Unit 3 in 1960 and Unit 4 in 1961. In early 2012, Units 1 and 3 with a combined power generation capacity of 280 megawatts were retired. Units 2 and 4 control SO₂ emissions by a DSI system and have LNB for NO_x controls (see Table 8 of Appendix F for source calculated control efficiencies). Both Units 2 and 4 will be retired per the 2019 IRP for Duke in 2022. The units were also retired in the NEEDsv620 per CAMD's December 2020 update.

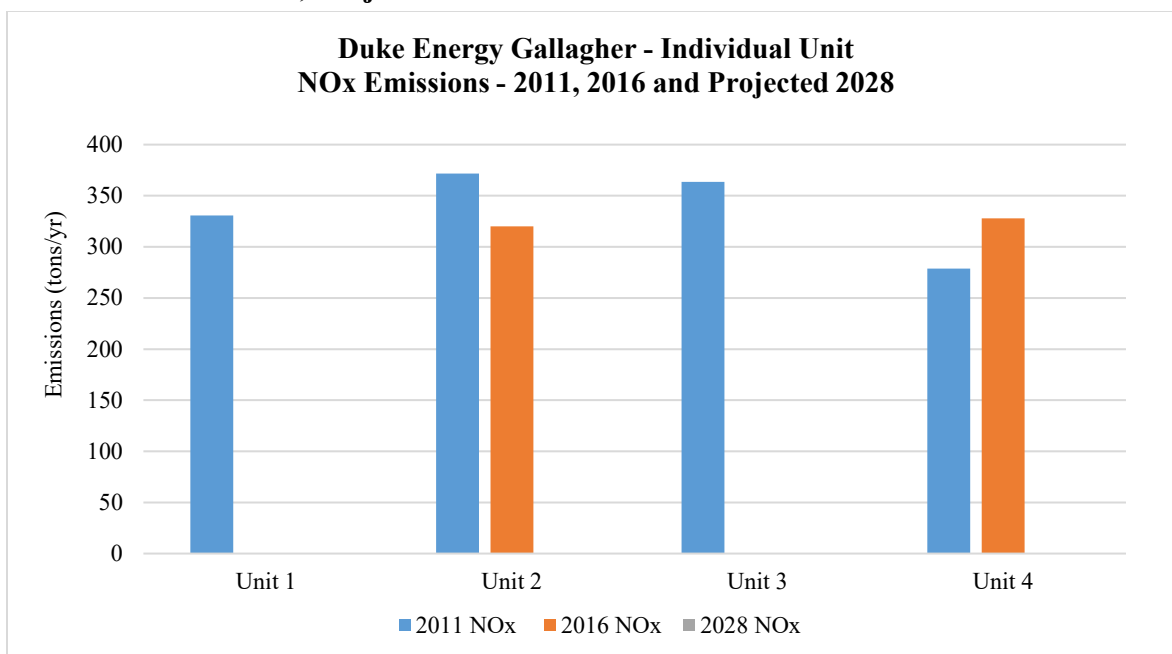
Gallagher's 2028 EGU NO_x emissions are projected to be reduced by 648 tons from 2016 emission levels and SO₂ emissions are expected to be reduced by 1,457 tons from 2016 to 2028 as a result of the final two units retirements. In 2016, emissions at Unit 4 increased as a result of the retirement of Units 1 and 3. This is a result of the need to make up for a portion of the lost coal-fired power generation overall at the facility.

Graph 8-34 Duke Energy Gallagher NO_x and SO₂ Emissions Trends



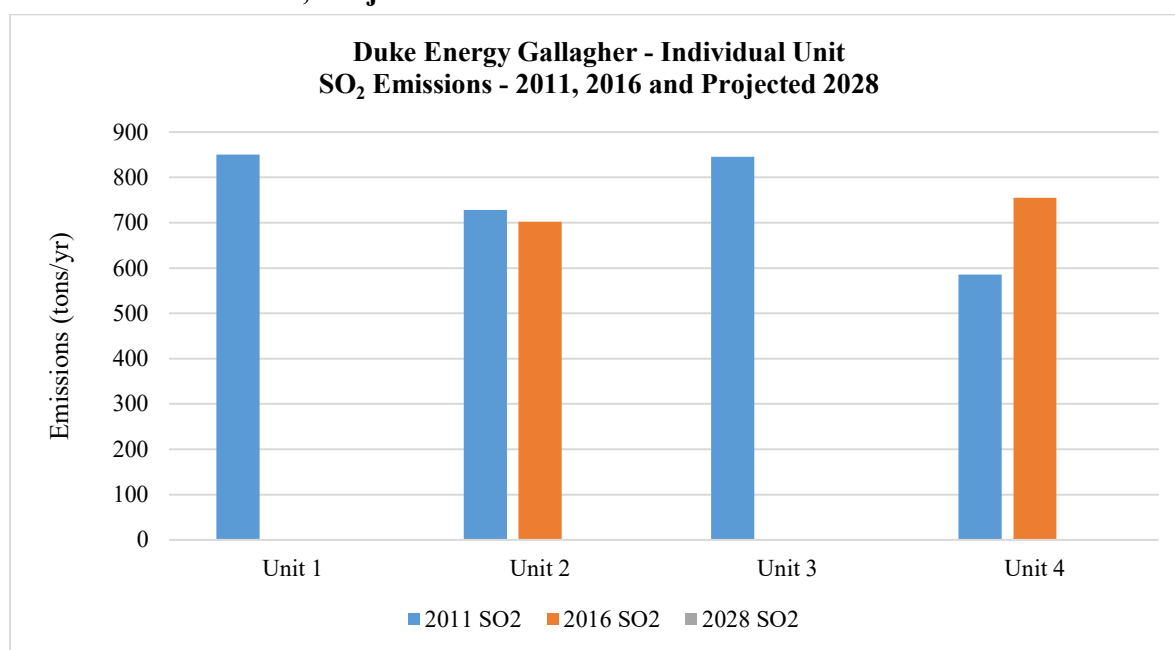
Graph 8-35 shows the unit-by-unit comparison of NO_x emissions at the Gallagher power plant. With the retirements of both Units 2 and 4, NO_x emissions at both units decrease from actual CAMD data for 2011 and 2016 to projected emissions by ERTAC in 2028 of zero. As can be seen, the retirements of Units 1 and 3 are reflected in no NO_x emissions from those units in 2016.

Graph 8-35 Unit Comparison of Duke Energy Gallagher NO_x Emissions - Actual 2011 and 2016, Projected 2028



Graph 8-36 shows the unit-by-unit comparison of SO₂ emissions at the Gallagher power plant. With the retirements of both Units 2 and 4, SO₂ emissions at both units decrease from actual CAMD data for 2011 and 2016 to projected emissions by ERTAC in 2028 of zero. As can be seen, the retirements of Units 1 and 3 are reflected in no SO₂ emissions from those units in 2016.

Graph 8-36 Unit Comparison of Duke Energy Gallagher SO₂ Emissions - Actual 2011 and 2016, Projected 2028



9.0 CLEAN AIR ACT REGULATIONS CONTROLLING ELECTRIC GENERATING UNITS

9.1 Cross State Air Pollution Rule

In 2005, EPA issued the Clean Air Interstate Rule to address interstate transport of ozone and fine particulate matter pollution. CAIR required certain states to limit annual emissions of NO_x and SO₂, which contribute to the formation of ozone and PM_{2.5}. The rule also included limits on ozone season NO_x emissions. In 2006, EPA published CAIR FIPs for states covered by CAIR, including Indiana, to ensure the required emission reductions were achieved on schedule. As the control strategy for the FIPs, EPA adopted the model SO₂ and NO_x cap-and-trade programs for fossil-fuel-fired power plants. CAIR established three separate cap-and-trade programs that most States used to achieve required reductions in developing state SIPs.

In 2008, the U. S. Court of Appeals for the DC Circuit issued a ruling vacating CAIR in its entirety. After EPA and other parties requested a hearing, the court revised its decision and remanded CAIR to U.S. EPA without vacatur. This ruling left CAIR and the CAIR FIPs, including the trading programs, in place until EPA issued a new rule to replace it.

In 2011, EPA finalized the CSAPR to replace CAIR and address power plant emissions that cross state lines and contribute to ozone and fine particle pollution in other states. In a separate, but related, regulatory action, EPA finalized a supplemental rulemaking on December 15, 2011 to require states to make summertime NO_x reductions under the CSAPR ozone season control program. To speed implementation, EPA adopted FIPs for each of the states covered by CSAPR and encouraged State to submit SIPs. CSAPR includes several emissions trading programs that require affected EGUs to hold emission allowances sufficient to cover their emissions of NO_x and/or SO₂ for each compliance period.

9.2 CSAPR Update Rule

On November 16, 2015, the EPA proposed an update to the CSAPR for the 2008 ozone NAAQS by issuing the proposed CSAPR Update Rule. This rule addressed the summertime (May – September) transport of ozone pollution in the eastern United States that crosses state lines to help downwind states and communities meet and maintain the 2008 ozone NAAQS. In July 2015 certain CSAPR budgets were remanded by the United States Court of Appeals for the D.C. Circuit. Then on September 7, 2016, the EPA revised the CSAPR ozone season NO_x program by finalizing an update to CSAPR for the 2008 ozone NAAQS, known as the CSAPR Update.

The CSAPR Update ozone season NO_x program largely replaced the original CSAPR ozone season NO_x program and the EPA also proposed FIPs in the CSAPR Update Rule. However, the rule was remanded. The EPA published the revised CSAPR Update Rule on April 30, 2021, and the rule became effective June 29, 2021. The CSAPR Update rule revises state emission budgets to reflect additional emission reductions from EGUs beginning with the 2021 ozone season. The rule reduces Indiana's budget for the 2021 NO_x Ozone Season to 13,051 tons with further NO_x emission budget reduction to 9,564 tons starting with the ozone season in 2024. It will be necessary to operate the NO_x reducing control devices already installed in order for EGUs to meet the state budget.

9.3 National Emission Standards for Hazardous Air Pollutants from Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units

On December 16, 2011, the EPA signed a rule to reduce emissions of toxic air pollutants from power plants. The National Emission Standards for Hazardous Air Pollutants (NESHAP) from Coal- and Oil-Fired Electric Utility Steam Generating Units, Subpart UUUUU, also referred to as the Mercury and Air Toxics Standards (MATS) rule for power plants, reduces toxic air pollutants from new and existing electric utility steam generating units larger than 25 MWe that burn coal or oil for the purpose of generating electricity for sale and distribution through the national electric grid to the public.

The MATS rule established numeric emission limits for mercury (Hg), PM, and hydrochloric acid (HCl) emissions from coal-fired EGUs and PM, HCl and hydrofluoric acid (HF) emissions from oil-fired EGUs. This includes numeric emission limits for SO₂ (as an alternative to HCl), individual non-mercury metal air toxics and total non-mercury metal air toxics (as alternatives to PM), and work practice standards, instead of numeric limits, to limit organic air toxics. All power plants are required to limit their toxic emissions, ultimately preventing 90% of the Hg in coal burned at power plants from being emitted into the air. As a result, the installed emission controls on EGUs must be operated at all times coal is burned. Reducing toxic power plant emissions will significantly decrease SO₂ emissions and fine particle pollution, as well.

9.4 2010 Sulfur Dioxide National Ambient Air Quality Standards

On June 2, 2010, the U.S. EPA promulgated a new primary NAAQS for sulfur dioxide, replacing the two primary standards of 140 parts per billion (ppb) evaluated over 24-hours and 30 ppb evaluated over an entire year with the 1-hour standard of 75 ppb. The primary SO₂ NAAQS is met when the 3-year average of the annual 99th percentile of the daily maximum 1-hour average concentration at any ambient air quality monitor in an area does not exceed 75 ppb.

10.0 FOUR-FACTOR ANALYSIS FOR CEMENT KILNS SOURCE CATEGORY

The 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. Control technologies to achieve RPGs are evaluated with respect to these four factors listed below:

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

The “four-factor” analyses conducted in this document includes identifying which NO_x and SO₂ emission control measures to consider, evaluating the four factors to be characterized for the NO_x and SO₂ emissions and control options considered, and evaluating the cost effectiveness of the emission control measures identified for the cement kiln source category and sources and Indiana’s non-EGU selected sources in accordance with 40 CFR 51.308(f)(2) of the RH Rule. This four-factor analysis will also include selecting NO_x and SO₂ emissions information for characterizing emissions-related factors and identifying applicable federal regulations that contribute NO_x and SO₂ emission control benefits in reducing regional haze by 2028 and beyond.

Sections 10.0 and 11.0 in this document were taken from the “Indiana RH SIP for the Second Implementation Period Nitrogen Oxides and Sulfur Dioxide Four-Factor Analysis for Cement

Kilns” document, dated May 18, 2021. This document is a standalone version of Indiana’s Four-Factor Analysis for Cement Kilns which can be found in Appendix G.

In anticipation for RH SIP development, LADCO procured the services of Amec Foster Wheeler Environment & Infrastructure, Inc. to develop a four-factor analysis document for LADCO states. Based on information from the contribution assessment, LADCO selected cement plants as one of the four source categories identified as large contributors of NO_x and SO₂ emissions for four-factor analysis.

This effort was undertaken in support of establishing RPGs for Northern Midwestern states for the implementation period ending 2028. The results of the cement kiln analysis were detailed in LADCO’s “Four-Factor Analysis for Regional Haze in the Northern Midwest Class I Areas, Methodology for Source Selection, Evaluation of Control Options, and Four-Factor Analysis,” document dated October 27, 2015. The source category description, the NO_x and SO₂ emissions and control measures descriptions and tables and the four statutory factors descriptions for the cement kiln source category outlined below were taken from this document which can be found at the following link: https://www.ladco.org/wp-content/uploads/Documents/Reports/Regional_Haze/Round2/2015_LADCO-4-Factor-Analysis-Regional-Haze.pdf.

In Indiana, two Portland cement manufacturing facilities met IDEM’s source selection criteria for the RH SIP second implementation period four-factor analysis. IDEM will evaluate the two Portland cement manufacturing facilities in terms of their cement kilns as a source category for the four-factor analysis. By focusing on cement kilns as a source category, IDEM can identify and describe all appropriate NO_x and SO₂ control measures for cement kilns and reference cement kiln BART analyses for other facilities in the Midwest region collected by EPA Region 8 and shared by the National Park Service, Federal Land Managers. This provides for a more robust analysis of potential NO_x and SO₂ control measures for the cement kilns at Indiana’s two Portland cement manufacturing facilities selected for the RH SIP second implementation period four-factor analysis.

10.1 Source Category Description for Cement Kilns

Portland cement is a main ingredient for concrete and other common building materials. Portland cement is mainly composed of clinker, a material formed by heating limestone and other ingredients to temperatures over 1,400 °C (2,650 °F). High combustion temperatures require large amounts of fuel and can result in significant emissions of NO_x and SO₂; crushing of ingredients and finished clinker can release dust and particles; and ammonia is sometimes produced during the heating of limestone. Figure 3.1 in Appendix A of the Indiana RH SIP for the Second Implementation Period Nitrogen Oxides and Sulfur Dioxide Four-Factor Analysis for Cement Kilns document in Appendix G shows a process flow diagram of a Portland cement facility. The process flow diagram (taken from AP-42) shows both wet and dry Portland cement processes.

The pyroprocessing step is the predominant source of gaseous pollutant emissions. In general, there are five different processes used in the Portland cement industry to accomplish the pyroprocessing step: the wet process, the dry process (long dry process),

the semidry process, the dry process with a preheater, and the dry process with a preheater/precalciner.

The kiln is a long cylinder rotating about its axis once every, one to two minutes. The axis is inclined at a slight angle, the end where fuel combustion occurs being lower. The rotation causes the ground limestone, silica, alumina, and iron (raw meal or kiln feed) to gradually pass along from where it enters at the cool end, to the hot end where it eventually drops out and cools. As the raw materials travel the length of the kiln, they are heated by the combustion of fuel at the discharge end of the kiln. In the long dry process, all the pyroprocessing activity occurs in the rotary kiln. The rotary kiln produces temperatures sufficient to heat the raw meal to sintering temperature (up to 1450 °C).

Dry process pyroprocessing systems have been improved in thermal efficiency and productive capacity through the addition of one or more cyclone-type preheater vessels in the gas stream exiting the rotary kiln. This system is called the preheater process. The vessels are arranged vertically, in series, and are supported by a structure known as the preheater tower. Hot exhaust gases from the rotary kiln pass counter currently through the downward-moving raw materials in the preheater vessels. Compared to the simple rotary kiln (long dry process), the heat transfer rate is significantly increased, the degree of heat utilization is greater, and the process time is markedly reduced by the intimate contact of the solid particles with the hot gases. The improved heat transfer allows the length of the rotary kiln to be reduced. An added benefit of the preheater operation is that hot gases from the preheater tower are used to help dry raw materials in the raw mill. Because the catch from the mechanical collectors, fabric filters, and/or electrostatic precipitators that follow the raw mill is returned to the process, these devices are considered production units as well as pollution control devices.

Additional thermal efficiencies and productivity gains have been achieved by diverting some of the fuel to a precalciner vessel (or calciner) at the base of the preheater tower. This system is called the preheater/precalciner process. A calciner vessel is a specially designed combustion chamber at the base of the preheater, into which a portion of the fuel needed for clinker production is injected. Typically, 60-75% of the fuel required for clinker formation is burned in the calciner. In the calciner, the raw materials are heated to approximately 650-1050°C. At this temperature, the decomposition of calcium carbonate occurs. The degree of calcination of feed entering the kiln is up to 90-95%.

The final component of the pyroprocessing system is the clinker cooler. The clinker cooler serves three main purposes.

- recoups up to 30% of the heat input to the kiln system,
- locks in desirable product qualities by freezing mineralogy, and
- makes it possible to handle the cooled clinker with conventional conveying equipment.

The more common types of clinker coolers are reciprocating grate, planetary, and rotary. In these coolers, the clinker is cooled from about 1,100°C to 90°C (2000°F to 200°F) by

ambient air that passes through the clinker and into the rotary kiln for use as combustion air. However, in the reciprocating grate cooler, lower clinker discharge temperatures are achieved by passing an additional quantity of air through the clinker. Because this additional air cannot be used in the kiln for efficient combustion, it is vented to the atmosphere, used for drying coal or raw materials, or used as a combustion air source for the precalciner.

Cement kilns are generally a counter flow process in which the feed is dumped into the high end of the kiln and the heat source is entered into the other. Coal is the fuel of choice in cement kilns, primarily because of its low cost, but also because the coal ash contributes to the product. In addition to conventional fuels, many Portland cement facilities are employing the use of petroleum derived coke (petcoke) blended with coal to fire kilns. The analysis of facilities in the LADCO states showed use of petcoke along with coal, liquid hazardous waste, and other fuels. Heat and feed are flowing in opposite directions within the kiln chamber so that the feed is constantly increasing in temperature from start to finish. As the feed passes through the kiln, gasses and byproducts are generated and collected. The resulting clinker, an intermediate product, is ground to make cement.

In the second portion of the cement manufacturing process, a series of blending and grinding operations completes the transformation of clinker into finished cement. Up to 5% gypsum or natural anhydrite is added to the clinker during grinding to control the cement setting time, and other specialty chemicals are added as needed to impart specific product properties. This finish milling is accomplished almost exclusively in ball or tube mills. Typically, finishing is conducted in a closed-circuit system, with product sizing by air separation.

10.2 Source Category NO_x Emissions and Potential Control Options

Kilns emit a mixture of fuel and thermal NO_x with a small portion coming from feed and prompt NO_x. Predominance of thermal and fuel NO_x in cement kiln combustion depends on the fuel being used and kiln design. Nitrogen content in fuel, fuel efficiency, and combustion temperatures impact NO_x creation.

Due to multiple factors affecting NO_x formation from combustion, there are different methods of reducing or controlling NO_x emissions from kilns. The potential control types can be categorized into the following three categories: pre-combustion NO_x controls, combustion modifications, and post-combustion NO_x controls. Pre-combustion NO_x controls include fuel substitution. This assessment does not analyze fuel switching as the costs are highly variable, and feasibility is dependent on individual kiln characteristics and functions. Combustion modifications in kilns are changes to one or more controllable variables in the combustion process itself, such as restriction of oxygen, flame temperature and/or residence time. Post-combustion NO_x controls utilize add-on control technologies to decrease the amount of formed NO_x before the combustion air is released to the atmosphere. It should be noted that certain physical or operational changes to a source may require analysis under the Prevention of Significant Deterioration (PSD) Program. It

should also be noted that the potentially applicable controls for any one source are highly dependent on the type of kiln, fuel(s) used, heat input capacity, and mode of operation.

For cement kilns, control technology options identified for NO_x include tuning/optimization, LNB, indirect firing, mid-kiln firing, SCR, and SNCR. Table 10-1 on the following page summarizes appropriate NO_x control options for cement manufacturing kilns.

Table 10-1 Source Category Potential NO_x Control Options for Cement Kilns

Technology	Description	Applicability	Performance
Tuning/Optimization ³	Process optimizing such as flame shaping and temperature profile	Potential control measure for all cement manufacturing kilns	Varies
LNB ¹	Advanced burner design that controls oxygen, flame temperature, and/or residence time with controlled fuel feed	Potential control measure for all cement manufacturing kilns	10-20% reduction in NO _x
LNB + Indirect Firing ^{1,2}	Advanced burner design that controls oxygen, flame temperature, and/or residence time with controlled fuel feed	Potential control measure for all cement kilns. Dependent on fuels burned, kiln use, and kiln configuration.	10-40% reduction in NO _x
Mid-Kiln Firing ³	Injecting solid fuel (usually tire derived fuel) into midpoint of kiln system	Potential control measure for all cement kilns. Dependent on fuels burned, kiln use, and kiln configuration.	10-55% reduction in NO _x
LNB + Mid-Kiln Firing ¹	Advanced burner design that controls oxygen, flame temperature, and/or residence time with fuel injection at mid-point of kiln system	Potential control measure for all cement kilns. Dependent on fuels burned, kiln use, and kiln configuration.	45% reduction in NO _x
SNCR ⁴	A reducing agent such as ammonia is introduced into the flue gas stream to form nitrogen gas	Potential control measure for all cement kilns. Dependent on fuels burned, kiln use, and kiln configuration.	45% reduction in NO _x
SCR ^{1,2,4,5}	A reducing agent such as ammonia is introduced into the flue gas stream to form nitrogen gas in the presence of a catalyst	Potential control measure for all preheater and preheater/precalciner cement kilns. Dependent on fuels burned, kiln use, and kiln configuration.	70-90% reduction in NO _x

Note: EPA Air Pollution Control Manual cites 12-77% reduction with NH₃ based SNCR (2019), with BART application achieving 35-58% reduction, with a median of 40%.

Table references:

1. *Midwest Regional Planning Organization Cement BART Engineering Analysis*, LADCO, March 2005.
2. *BART Determination Support Document for Lafarge North America Seattle Plant*, Washington State Department of Ecology, October 2008.
3. *Supplementary Information for Four-Factor Analyses by WRAP States*, WRAP and WGQ, May 2009.
4. *Control Technology Analysis for Carolinas Cement Company LLC*. Environmental Quality Management, Inc., Feb 2008.
5. *Attachment to Letter, RE: National Association of Clean Air Agencies*. Docket ID No. EPA-HQ-OAR-2007-0877, Sep 2008.

10.2.1 Source Category Potential Combustion NO_x Control Options

Kiln Tuning/Optimization

Kiln tuning and optimization is a baseline NO_x control that applies to cement manufacturing. This pre-combustion control includes improving fuel efficiency and modifications to the kiln design to reduce NO_x emissions. Efficiency and cost effectiveness of this pre-combustion NO_x control is difficult to quantify as designs and processes are highly variable.

Low NO_x Burners /Indirect Firing

LNB reduces NO_x formation by controlling oxygen, flame temperature, and/or residence time. Cement kilns utilize staged air low-NO_x burners. Central air and swirl air generate an optimum internal recirculation, with a correspondingly high residence time for the combustion of solid fuels. Staged air LNB increases residence time and thus is more effective for fuel oil kilns which produce higher fuel NO_x emissions. Furthermore, by internal recirculation of the combustion gases the spontaneous formation of NO_x decreases. In addition, by reducing the peak flame temperature, significantly less NO_x is formed in the process. LNB can be used on all types of cement manufacturing kilns.

Indirect firing systems are a type of combustion modification that utilizes pulverized fuel and transports the fuel to the burner via a dense phase conveying system which reduces air volume. This process creates a fuel rich flame which in turn decreases oxygen that is necessary in NO_x formation. LNB can be used in collaboration with indirect firing and has control efficiencies of 10 to 40 percent. When only LNB is applied to cement kilns, a reduction in 10-20 percent is observed (LADCO, 2005). Indirect firing with LNB can be used on all systems in cement production.

Staged Combustion

Staged combustion of fuel includes the use of precalciner and mid-kiln firing. In mid-kiln firing, fuel is injected near the mid-point of the kiln using a feed fork, pivoting doors, and a drop tube that extends into the kiln wall. Fuel injection occurs once in a revolution. Typically, fuel with low fuel NO_x is used. This combustion modification reduces the heat needed thus leading to a reduction in thermal NO_x formation. Mid-kiln firing has been used in long wet and dry kilns but can also be used in preheater and preheater/precalciner systems.

Preheater/precalciner kilns are inherently a form of staged combustion. Up to 70% of the total fuel consumption in a preheater/precalciner kiln is combusted in the calciner. The operating temperature in the calciner is significantly lower than in the kiln. The ideal temperature range is approximately 900°C while the kiln temperature is between 1500°C and 1700°C. Since most of the fuel is combusted at a lower temperature, less thermal NO_x is formed. In addition, combustion in the calciner can occur with less excess oxygen resulting in slightly reducing conditions which also reduces NO_x formation.

With preheater and preheater/precalciner systems, fuel can also be introduced into the riser duct using a drop chute with an airlock which causes combustion to be initiated in the riser duct which is located between the calciner and rotary kiln. Combustion continues within the rotary kiln section away from the high temperatures of the main kiln burner.

Mid-kiln firing on its own can reduce NO_x from 11 to 55 percent depending on fuel used and kiln design (EC/R Incorporated, 2009). Paired with a LNB, up to a 45 percent reduction has been noted (LADCO, 2005).

Water Injection

Water injection is a well-established mechanism for controlling thermal NO_x emissions. To control the formation of thermal NO_x, water is injected with the fuel to reduce flame temperature. For cyclone boilers that generate high levels of thermal NO_x, reductions of 22% have been demonstrated and higher reductions are possible. Industry experience has shown up to a 50% control efficiency for water injection into the burning zone of a cement kiln. Liquid Hazardous Waste Fuel (LHWF) typically contains up to 18% moisture and has the same effect as water injection on the formation of thermal NO_x. Inherent moisture of the LHWF injected into the kiln or the calciner has the effect of cooling the flame and reducing NO_x emissions. The use of waste derived fuel is recognized as a NO_x control on Kilns #1 and #2 at the Lafarge North America Paulding, Ohio plant and at the Lehigh Cement Waco, Texas plant (see Summary table in Appendix C of the Indiana RH SIP for the Second Implementation Period Nitrogen Oxides and Sulfur Dioxide Four-Factor Analysis for Cement Kilns document in Appendix G).

10.2.2 Source Category Post-Combustion Potential NO_x Control Options

Selective Non-Catalytic Reduction

SNCR is another control option that is dependent on kiln type. An ammonia containing solution (e.g., anhydrous ammonia, aqueous ammonia, or urea) is injected into the preheater tower for NO_x reduction. The ammonia reacts with the NO_x to form nitrogen and water. Optimum temperature ranges from 1600° - 2000°F which must be maintained for the reaction to occur. At lower temperatures, the reaction rates slow and increases the chance of ammonia slip, although it is noted that a minimum of 5 parts per million ammonia slip may still occur during normal SNCR processes (Environmental Quality Management, Inc., 2008). If temperatures exceed the optimal range, the reactions do not occur; and ammonia or urea reagent will oxidize and result in even greater NO_x emissions. SNCR secondary reactions can form precipitate which can foul the preheater and interrupt kiln processes. Exercising caution with ammonia input quantity and adding wet scrubbing can help reduce ammonia emissions. As is the case with SCR, SNCR works best when applied with preheater and preheater/precalciner kilns with NO_x reductions of 45 percent (Environmental Quality Management, Inc., 2008).

Selective Catalytic Reduction

In SCR, anhydrous ammonia is injected into NO_x containing exhaust gas and directed through a catalyst bed to reduce NO_x to nitrogen and water. Catalysts typically used include vanadium pentoxide, zeolite, or titanium dioxide. To complete the reaction, a temperature range of 480° - 800°F is required. Due to this temperature requirement, SCR application would theoretically work best for preheater and/or precalciner kilns but has limited application on cement kilns for NO_x control in the United States. The catalyst bed can be placed after the preheater tower or before or after the PM control device. SCR placement is important and leads to control design decisions. If the SCR is placed at the preheater tower, temperature requirements are met but the catalyst is subject to fouling by particulate, alkalis, lime, and sulfur dioxide in cement kiln gases. Fouling can cause the catalyst to become unreactive, thus allowing injected ammonia to escape through the system which is known as ammonia slip. There are sulfur tolerant SCR catalysts available that can limit SO₂ oxidation to less than 1 percent (LADCO, 2005). Particulate accumulation can be reduced with soot blowers. If the SCR is placed after the PM control device, reheating of exhaust gases will be required for the catalyst reaction. SCR NO_x reduction observed ranges from 70 to 90 percent.

10.3 Source Category Four-Factor Analysis of Potential NO_x Control Options

The four-factor analysis approach has been utilized to analyze the potential NO_x control options presented in Table 10-1 on page 96. The four factors that must be taken into consideration for potential NO_x control options in determining reasonable progress for the cement kiln source category are outlined below.

10.3.1 Source Category Cost of Compliance for Potential NO_x Control Options

To compare the various control options, information has been compiled on the cost effectiveness of retrofitting controls. As a rule of thumb, cost effectiveness increases with the amount of cement produced by the facility.

For this assessment, cost effectiveness was pulled from various sources, compiled into a general range, and converted into 2015 dollars. This information is summarized in Table 10-2 on page 101. Please note that the ranges will vary less than what is shown depending on the size and type of kiln.

Factors contributing to capital costs include installation costs, control hardware, and additional add-ons required due to site-specific conditions. LNB with mid-kiln/indirect firing generally will be more cost effective than the current post-combustion control options. When LNB is applied to preheater/precalciner kilns, costs are generally lower than long dry kilns. However due to less pollutants emitted from preheater/precalciner kilns than dry kilns, the cost values are slightly higher for the former type when comparing similar sized facilities. Site-specific factors can impose additional costs.

For preheater/precalciner kilns, an SNCR system may be considered. An SNCR system consists of an ammonia storage tank, blower or compressor, and various valves, indicators, and controls; the ammonia injection grid; and a continuous emissions monitoring system. No reactor is required for SNCR as the urea or other reducing agent can be injected directly into the gas stream. This reduces capital costs for the system; however, operating costs are higher due to lower efficiency and more reagents use and NO_x reduction efficiency is greatly increased.

An SCR system includes catalyst materials; the ammonia system including a vaporizer, storage tank, blower or compressor, and various valves, indicators, and controls; the ammonia injection grid; the SCR reactor housing (which contains the catalyst); transition ductwork; and a continuous emissions monitoring system. The decision to use aqua ammonia or urea instead of anhydrous ammonia can play a small role in affecting costs because aqua ammonia and urea have higher capital and operating costs. SCR systems are generally designed for use in combustion systems with a much lower dust loading (e.g., power plants, boilers). The high dust loading contributes to catalyst deactivation mechanisms including plugging, masking, encrustations, and poisoning. To function in a cement kiln, the SCR system may require additional particulate removal equipment and associating ductwork depending on site specific factors. If the exhaust gas temperature range entering the SCR does not meet the optimal catalyst temperature requirements, modifications may have to be made to increase/decrease the temperature. Additional gas cleaning may be required to maintain the SCR as well as a bypass installation to protect the SCR during startup, shutdown, and malfunction which could potentially foul the catalyst. A preheater/precalciner kiln is generally more cost effective when compared to a dry kiln.

Table 10-2 Source Category Cost Effectiveness of Potential NO_x Control Options

Control Option	Specific Design Parameters Identified	Cost Effectiveness (2015 \$/ton)^a	Factors Affecting Cost	Potential Applicability to Specific Facilities (Unit ID)
Tuning/Optimization ³	None	Low	Engineering and contractor costs	05-01 ^b
LNB ¹	None	No Data	Equipment, installation, and engineering	05-01
LNB + Indirect Firing ^{1,2}	Specific temperature range, oxygen levels, and flame length	\$200-\$21,100	Equipment, installation, and engineering	05-01
Mid-Kiln Firing ³	Specific fuel injection location	\$600-\$3,600	Equipment, installation, and engineering	05-01
LNB + Mid-Kiln Firing ¹	Specific temperature range, specific fuel injection, oxygen levels, and flame length	No Data	Equipment, installation, and engineering	05-01
SNCR ⁴	Specific temperature range; PM reduction, ammonia injection, preheater kiln	\$1,400	Equipment, installation, engineering, energy use, waste removal, and reduction agent	None
SCR ^{1,2,4,5}	Specific temperature range; PM reduction, ammonia injection, catalyst bed	\$600-\$17,700	Equipment, installation, engineering, energy use, waste removal, reduction agent, and catalyst	05-01

^a Costs have been converted into 2015 dollars using Consumer Price Index (CPI) data through August 2015.

^b Table 6-1 Point Source NO_x Information Collected for Select Cement and Lime Kilns in the LADCO Region, *Four-Factor Analysis for Regional Haze in the Northern Midwest Class I Area*, LADCO, 2015, page 6-2.

Table references:

1. *Midwest Regional Planning Organization Cement BART Engineering Analysis*, LADCO, March 2005.
2. *BART Determination Support Document for Lafarge North America Seattle Plant*, Washington State Department of Ecology, October 2008.
3. *Supplementary Information for Four Factor Analyses by WRAP States*, WRAP and WGQ, May 2009.
4. *Control Technology Analysis for Carolinas Cement Company LLC*. Environmental Quality Management, Inc., Feb 2008.
5. *Attachment to Letter, RE: National Association of Clean Air Agencies*. Docket ID No. EPA-HQ-OAR-2007-0877, Sep 2008.

10.3.2 Source Category Time Necessary for Potential NO_x Control Options Compliance

Sources are generally given between two and five years to implement changes for compliance with new regulations. Maximum achievable control technology (MACT) standards typically allow three years for compliance and BART emission limitations require compliance no more than five years after regional haze SIP approval by the EPA. Under the NO_x SIP Call for Phases I and II, EPA allowed for three and a half and two years, respectively, after the SIP submittal date for compliance. Combustion modifications and post-combustion NO_x controls require significant time for engineering, construction, and facility preparedness. After SIP submittal, a two-year period is assumed to be adequate for pre-combustion controls and a three-year period for post-combustion control installation. Substantially less time would be required for boiler optimization and tuning which can be implemented within a few months to a year.

10.3.3 Source Category Energy and Non-Air Impacts of Potential NO_x Control Options

With LNB, flame efficiency can be impacted thus increasing fuel consumption. Vendors claim that new LNB designs do not lower fuel efficiency so a small increase in fuel consumption may occur. If catalyst bed or reaction temperatures are not met for post-combustion controls, additional fuel or electrical power may be required to heat or cool the gas stream.

When SNCR, SCR, and RNCR conditions are not met (e.g., temperature range), the required reactions to promote NO_x reduction do not occur thus leading to ammonia slip or an increase in particulate emissions. In the presence of a catalyst, the increase in particulate emissions can potentially foul the catalyst. With ammonia slip, ammonia is permitted through the stack to react with sulfur and nitrogen oxides to form particulate, thus, contributing to regional haze. Ammonia slip can also contaminate surface waters by deposition. For SNCR, SCR, and RNCR, storage of anhydrous ammonia is accompanied with more environmental and safety risk than with aqueous ammonia or urea storage. Additionally, spent catalyst beds will need to be changed periodically resulting in an increase in waste disposal.

10.3.4 Source Category Remaining Useful Life of Potential NO_x Control Options

According to MARAMA's Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I areas, the remaining useful life of each emission unit is a minimum of at least 10 years. With proper maintenance and upkeep, some units can operate for 20-30 years more.

10.4 Source Category SO₂ Emissions and Potential Control Options

Sulfur dioxide is formed primarily from sulfur in the raw materials. Sulfur content in fuels and raw materials can vary according to geographic location. In contrast to industrial boilers, SO₂ emissions from cement kilns are not strongly dependent on fuel sulfur content but rather the amount of sulfide (e.g., pyrite) in kiln feedstocks and the molar ratio of total sulfur to total alkali input to the system. Oxidizing or reducing conditions and their location within the kiln as well as temperature profile in the kiln system can impact SO₂ emissions. Additionally, inherent reduction of SO₂ emissions occurs in cement production due to the alkaline nature of cement which promotes direct absorption of SO₂ into the product.

Potential control types can be categorized into the following three categories: pre-combustion SO₂ controls, combustion modifications, and post-combustion SO₂ controls. Pre-combustion SO₂ controls include fuel substitution. This assessment does not analyze the cost effectiveness of fuel switching because costs are highly variable and SO₂ emissions are not strongly dependent on sulfur content in fuel but rather on the sulfur content in kiln feedstock. Combustion modifications are changes to one or more controllable variables in the combustion process itself. Retrofit combustion modifications exist but are very invasive and may be possible for only a small number of existing kilns. For this reason, these modifications are not assessed in this report. Post-combustion SO₂ controls utilize add-on control technologies to decrease the amount of formed SO₂ before the combustion air is release to the atmosphere. It should be noted that certain physical or operational changes to a source may require analysis under the PSD program. It should also be noted that the potentially applicable controls for any one source are highly dependent on the type of kiln, fuel(s) used, heat input capacity, and mode of operation. Table 10-3 on the following page summarizes appropriate SO₂ control options for cement manufacturing kilns.

Table 10-3 Source Category Potential SO₂ Control Technologies for Cement Kilns

Technology	Description	Applicability	Performance
Conventional Dry Flue Gas Desulfurization (FGD) – Dry Sorbent Injection ^{1,2,3,4}	An absorbent reagent such as lime slurry is introduced into the flue gas stream through direct injection to absorb SO ₂ , creating a dry solid which is caught in a downstream fabric filter or ESP	Potential control measure for all cement kilns; dependent on fuels burned, kiln use, and kiln configuration	25-50% reduction in SO ₂
Conventional Dry Flue Gas Desulfurization (FGD) – Spray Dryer ^{1,5,6}	An absorbent reagent such as lime, calcium hydrate, limestone or soda ash is introduced into the flue gas stream through spray in an absorption tower to absorb SO ₂ , creating a dry solid which is caught in a downstream fabric filter or ESP	Potential control measure for all cement manufacturing kilns; dependent on fuels burned, kiln use, and kiln configuration	90-95% reduction in SO ₂
Advanced Flue Gas Desulfurization (FGD) ¹	A slurry reagent is sprayed onto cooled/humidified flue gas to absorb SO ₂ , creating calcium sulfate that is oxidized to create wallboard-grade gypsum	Potential control measure for all cement kilns; dependent on fuels burned, kiln use, and kiln configuration	95-99.5% reduction in SO ₂
Wet Flue Gas Desulfurization (FGD) ^{1,2,3,4,5,6}	A scrubbing reagent such as caustic, crushed limestone, or lime is introduced into the flue gas stream to absorb SO ₂ , creating liquid or sludge waste	Potential control measure for all cement and lime manufacturing kilns; dependent on fuels burned, kiln use, and kiln configuration	40-99% reduction in SO ₂

Table references:

1. *Midwest Regional Planning Organization Cement BART Engineering Analysis*, LADCO, March 2005.
2. *BART Determination Support Document for Lafarge North America Seattle Plant*, Washington State Department of Ecology, October 2008.
3. *Prevention of Significant Air Quality Deterioration Review Preliminary Determination - CEMEX Southeast, LLC*, Georgia EPD, December 2008.
4. *Control Technology Analysis for Carolinas Cement Company LLC*, Environmental Quality Management, Inc., February 2008.
5. *Technical Evaluation & Preliminary Determination - Jacksonville Lime LLC*, Florida DEP, December 2013.
6. *Subject: Engineering Evaluation of Prevention of Significant Deterioration Permit Application Submitted by Carmeuse Lime & Stone for its Winchester Facility (Registration No. 80504)*. VA DEQ, April 2014.

10.4.1 Source Category Pre-Combustion Potential SO₂ Control Options

Flue Gas Desulfurization

For cement kilns, control technology options identified for SO₂ include conventional dry FGD, wet FGD, and advanced flue gas desulfurization (AFGD). Descriptions of each of these technologies are provided below and a summary of these controls is provided in Table 10-3 on the previous page.

Conventional Dry Flue Gas Desulfurization

There are two types of conventional dry FGD controls: DSI systems and spray dryer absorption (SDA) systems.

In DSI systems, lime, calcium hydrate, limestone or soda ash is injected into the flue gas stream producing solid particles of calcium sulfite and calcium sulfate (CaSO₃ or CaSO₄). These particles and excess reagent are removed from the gas stream using a particulate control device. SO₂ removal efficiency typically ranges from 25-50 percent and depends on absorbent injection location, temperature, degree of mixing, retention time, kiln type, and additional add-ons. Depending on site-specific processes, DSI systems can and have been applied to cement kilns.

In an SDA system, lime slurry is sprayed into an absorption tower where SO₂ is absorbed into the slurry, forming a mixture of calcium sulfite and calcium sulfate. The water evaporates before the droplets reach the bottom of the tower due to the liquid-to-gas ratio. The dry solids created due to the evaporation are collected with a fabric filter or ESP. When applied to cement kilns, spray dryers are expected to reduce SO₂ emissions by 90 to 95 percent (LADCO, 2005).

According to MARAMA's Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I areas, SDA systems are typically applied to preheater or preheater/precalciner kilns in the cement industry. In long dry kilns, two methods are used to cool down exhaust gases. Spray water is introduced into the feed end of the kiln or by dilution air-cooling once the gases leave the kiln. An SDA equivalent application for long dry kilns is to use a conditioning tower to replace the method of cooling and pair with an alkaline slurry system to reduce SO₂ emissions. For long wet kilns, an SDA system should be applied with care because the addition of the lime slurry may drop the exhaust gases temperature below acid adiabatic saturation temperatures, plugging and causing corrosion problems in the downstream particulate control device, duct work, and induced draft fan (LADCO, 2005).

It must be noted that exhaust gases that exit at or near the adiabatic saturation temperatures can create problems with dry FGD by causing the baghouse filter cake to become saturated with moisture and plug both the filters and the dust removal system. In addition, the lime slurry would not dry properly and would plug up the dust collection system. However, some argue that SO₂ removal, actually, occurs on the filter cake. Ultimately, it is important that exit gas temperatures are above the adiabatic saturation temperatures (LADCO, 2005).

Advanced Flue Gas Desulfurization

AFGD utilizes a single absorber to accomplish three actions at once. Before entering the absorber, incoming flue gas is cooled and humidified with process wet suppression. As the quenched flue gas enters the absorber, reagent slurry is distributed via two tiers of fountain like sprays and onto a polymer grid packing that promotes gas/liquid contact. This is where SO₂ absorption, neutralization, and partial oxidation begins. The products formed are calcium sulfite and calcium sulfate. Slurry and absorbed SO₂ fall into the slurry reservoir where unreacted acids are neutralized further by injected dry limestone powder.

Meanwhile, air is injected into the slurry through mixing with the use of an air rotary sparger which oxidizes the primary product, calcium sulfite, into gypsum. Fixed air spargers are also used to supplement complete oxidation. Slurry is recycled back to the absorber grid while the gypsum is drawn from the reservoir, dewatered, and washed to remove chlorides. The liquid generated by dewatering is returned to the reservoir with a slipstream headed to the wastewater evaporation system to be injected into the hot flue gas prior to the ESP which is placed before the absorber. The gypsum created wallboard quality gypsum which can be added in the final grinding process to regulate concrete setting time. Particulate collected in the ESP consist of water evaporates and dissolved solids that can be collected for disposal or sale.

After going through the polymer grid packing, the flue gas continues onto a large gas/liquid disengagement zone above the slurry reservoir where the SO₂ has been absorbed and finally exiting through a horizontal mist eliminator.

AFGD has not been used in cement kilns before. In the Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I areas, MACTEC recommends the use of an AFGD system because it is similar to wet FGD and can produce commercial grade gypsum. AFGD control efficiency ranges from 95 to 99.5 percent (LADCO, 2005). AFGD is not generally considered technically feasible for cement kilns.

Wet Flue Gas Desulfurization

Caustic, crushed limestone, and lime are used as scrubbing agents in wet FGD. In the presence of these agents, SO₂ from the exhaust gases is absorbed into the contact liquid. When lime or limestone is used, additional steps and equipment are required to stabilize the watery calcium sulfite or calcium sulfate sludge produced.

Calcium sulfate sludge can be dewatered but in order to create the calcium sulfate, an air injection blower is needed to supply oxygen necessary for the reaction to occur. In cement kilns, SO₂ reduction efficiency ranges from 40 to 99 percent. When directly applied to the exhaust gas stream, calcium sulfate scaling and cementitious buildup can occur when used for acid gas control. To prevent these issues from happening, a particulate control device can be installed. However, if the particulate control device fails this could impact the downstream wet scrubber.

10.5 Source Category Four-Factor Analysis of Potential SO₂ Control Options

The four-factor analysis approach has been utilized to analyze the potential SO₂ control options presented in Table 10-3 page 104. The four factors that must be taken into consideration for potential SO₂ control options in determining reasonable progress for the cement kiln source category are outlined below.

10.5.1 Source Category Cost of Compliance for Potential SO₂ Control Options

Information on cost effectiveness of retrofitting controls onto kilns has been compiled from various sources. It is important to note that the values provided are estimated and actual retrofit control costs may be higher or lower depending on the utilization and production scale of the kiln as well as specific capital costs associated with the design.

Pre-combustion (e.g., fuel substitution) and combustion modifications were not discussed in detail in this assessment due to highly variable costs determined by individual kiln characteristics and functions.

Post-combustion SO₂ control costs can be impacted by scrubbing agent used, additional equipment required for promoting SO₂ reduction reactions, and the associated energy costs. Lime is generally less expensive and readily available. However, if other scrubbing agents are used this could increase costs. For the AFGD process, spargers and blowers are necessary to oxidize the waste product and additional equipment are required to dewater the gypsum hydrate. In order to keep the flue gas above adiabatic saturation in dry FGD, equipment like an evaporative cooler, a heat exchanger, or a heat recovery boiler will be needed. These additions will run up the costs with purchase, installation, and associated energy costs. However, costs may be offset with the sale of gypsum generated by AFGD. Wet FGD systems also provide another level of particulate control.

In assessing cost effectiveness of SO₂ controls for lime plants, PSD evaluations of two lime plants, Jacksonville Lime LLC (Florida) and Carmeuse Lime & Stone (Virginia), were found. In each PSD analysis, both the state and the facility agreed that application of SO₂ controls may not be cost effective due to inherent scrubbing of SO₂ within the process.

Table 10-4 on the following page summarizes the cost effectiveness and factors affecting the cost of each control option addressed in this analysis, as well as potential applicability to the specific facilities analyzed as part of this report. Costs have been converted into 2015 dollars using Consumer Price Index (CPI) data through August 2015. Please note that some costs may have decreased since the original analyses; however, this analysis has only used past data available. A confidential key to the unit IDs is provided on the informational disc included with this report. It must be pointed out that the cost-effective ranges for cement kilns vary greatly. This range includes both long dry kilns and preheater/precalciner kilns, the latter of which exhibits higher cost per ton of SO₂.

Table 10-4 Source Category Cost Effectiveness of Potential SO₂ Control Options

Control Option	Specific Design Parameters Identified	Cost Effectiveness (2015 \$/ton)^a	Factors Affecting Cost
Conventional Dry Flue Gas Desulfurization (FGD) – Dry Sorbent Injection ^{1,2,3,4}	Direct flue gas application, lime/calcium hydrate/limestone/soda ash injection, PM control device	\$2,400-\$9,000 (cement)	Equipment, installation, engineering, reagent, and waste removal
Conventional Dry Flue Gas Desulfurization (FGD) – Spray Dryer ^{1,5,6}	An absorbent reagent such as lime, calcium hydrate, limestone or soda ash is introduced into the flue gas stream through spray in an absorption tower to absorb SO ₂ , creating a dry solid which is caught in a downstream fabric filter or ESP	\$2,300-\$88,800 (cement)	Equipment, installation, engineering, reagent, and waste removal
Advanced Flue Gas Desulfurization (FGD) ¹	Lime slurry injection, PM control device	\$2,400-\$47,100 (cement)	Equipment, installation, engineering, reagent, energy use, waste removal, and byproduct resale
Wet Flue Gas Desulfurization (FGD) ^{1,2,3,4,5,6}	Caustic/crushed limestone/lime slurry, scrubber vessel pressure drop, air injection blower, PM control device	\$1,500-\$78,800 (cement)	Equipment, installation, engineering, reagent, energy use, and waste removal

^a Costs have been converted into 2015 dollars using Consumer Price Index (CPI) data through August 2015.

Table references:

1. *Midwest Regional Planning Organization Cement BART Engineering Analysis*, LADCO, March 2005.
2. *BART Determination Support Document for Lafarge North America Seattle Plant*, Washington State Department of Ecology, October 2008.
3. *Prevention of Significant Air Quality Deterioration Review Preliminary Determination - CEMEX Southeast, LLC*, Georgia EPD, December 2008.
4. *Control Technology Analysis for Carolinas Cement Company LLC*, Environmental Quality Management, Inc., February 2008.

10.5.2 Source Category Time Necessary for Potential SO₂ Control Options Compliance

Sources are generally given between two and five years to implement changes for compliance with new regulations. MACT standards typically allow three years for compliance and BART emission limitations require compliance no more than five years after regional haze SIP approval by the EPA. Combustion modifications and post-combustion controls require significant time for engineering, construction, and facility preparedness. Two to five years would typically be appropriate, depending on the size of the unit and control options selected.

10.5.3 Source Category Energy and Non-Air Impacts of Potential SO₂ Control Options

Post-combustion SO₂ controls can impact energy use and the environment in forms other than air quality. Non-air environmental impacts include solid, liquid, and/or hazardous waste generation and deposition of atmospheric pollutants on land or water. Dry FGD generates particulate that is collected by PM control devices that will need to be disposed. Wet FGD generates wastewater and sludge that increases a facility's wastewater treatment and solid waste management burdens. Even though AFGD generally creates commercial grade gypsum, gypsum that does not meet industry standards can be created due to fuels used.

Post-combustion SO₂ controls may also impact energy use for kilns. Wet FGD tends to consume more energy due to an operational pressure drop in the scrubber vessel. When systems utilize more reagent for the associated process, more energy consumption occurs. For some technologies, a flue gas reheater may be essential to the system thus increasing energy use.

10.5.4 Source Category Remaining Useful Life for SO₂ Control Options

According to MARAMA's Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I areas, the remaining useful life of each emission unit is a minimum of at least 10 years. With proper maintenance and upkeep, some units can operate for 20-30 years more.

10.6 Clean Air Act Regulations Controlling Cement Kilns

10.6.1 National Emission Standards for Hazardous Air Pollutants for the Portland Cement Manufacturing 40 CFR 63, Subpart LLL and New Source Performance Standards for Portland Cement Plants

The Portland cement manufacturing industry is governed by the revised amendments to the NESHAPs for the Portland Cement Manufacturing 40 CFR 63, Subpart LLL and New Source Performance Standards (NSPS) for Portland Cement Plants, 40 CFR 60, Subpart F. The EPA originally established the NESHAPs for the Portland cement manufacturing industry and NSPS for Portland cement plants in 1999 under sections 112(d) and 111(b) of the CAA.

On September 9, 2010, EPA finalized amendments to the NESHAPs for the Portland Cement Manufacturing Industry and New Source Performance Standards for Portland Cement Plants. The final 2010 NSPS for Portland cement plants revised and added, as applicable, emission limits for PM, opacity, NO_x, and SO₂ for facilities that commence construction, modification, or reconstruction after June 16, 2008, and included additional testing and monitoring requirements for affected sources.

On July 18, 2012, the EPA proposed amendments to the NESHAPs for the Portland cement source category and NSPS for Portland cement plants in response to petitions for reconsideration filed by the Portland cement industry and a federal court decision by the United States Court of Appeals for the District of Columbia Circuit to remand the 2010 amendments. The most significant amendment was to the NESHAP and NSPS for PM, which was the only change to the NSPS rule.

The NSPS emission limits for NO_x and SO₂ established in the 2010 amendments remained the same and the final rule was effective on February 12, 2013.

Subsequently, on November 19, 2014, the EPA issued a proposal to amend the two rules issued in February 2013 after the agency became aware of certain minor technical errors in those amendments. The final amendments to correct these errors became effective on July 1, 2015 and remains in effect at this time.

10.6.2 National Emission Standards for Hazardous Air Pollutants from Hazardous Waste Combustors 40 CFR 63, Subpart EEE

Hazardous waste-burning cement kilns are governed by the NESHAP for Hazardous Waste Combustors, 40 CFR 63, Subpart EEE. The original amendments were proposed on April 19, 1996, under the joint authority the CAA and the Resource Conservation and Recovery Act. The NESHAP limits emissions of chlorinated dioxins and furans, other toxic organic compounds, toxic metals, hydrochloric acid, chlorine gas, and particulate matter. These standards reflect the performance of Maximum Achievable Control Technologies (MACT) as specified by the CAA.

On June 19, 1998, the NESHAPs for hazardous waste combustors was published in the FR. There were numerous actions taken between 1998 when the first NESHAPs amendments were finalized and 2008 when the current amendments became effective. On October 12, 2005, the NESHAP for new and existing sources at hazardous waste combustion facilities was finalized. Four petitions for reconsideration of the final rule were filed. On March 23, 2006 and September 6, 2006, EPA granted reconsideration with respect to issues raised by the petitions. EPA also re-opened the rule to consider comments relating to a post-promulgation decision of the United States Court of Appeals for the D.C. Circuit. As a result of this reconsideration process, EPA revised the new source standard for particulate matter, the particulate matter detection system provisions, and revisions to the health-based compliance alternative for total chlorine. Several corrections and clarifications were also made to the final NESHAP amendments which were finalized on October 28, 2008.

10.7 Source Category Selected Best Available Retrofit Technology

10.7.1 Source Category Reasonable Level of Control for NO_x Emissions

The largest contributor to overall NO_x emissions from cement kilns is thermal NO_x which results from high temperature combustion as described in Section 10.2 on page 94. Combustion modifications are an efficient way to reduce the formation of thermal NO_x by modifying the way oxygen or fuel is provided for combustion.

Low-NO_x burner systems are available for all kilns for NO_x emissions control. Table 10-1 on page 96 reports potential NO_x reduction rates of 10-55 percent with the installation of low-NO_x burners depending on fuel used, type of kiln, type of low-NO_x burner, and operating conditions. When only LNB is applied to cement kilns, a reduction of 10-20 percent is observed (LADCO, 2005), however LNB can be used in collaboration with indirect firing for improved control efficiencies that range from 20 to 40 percent.

According to Table 10-1 on page 96, SNCR systems are also available for all kiln types and has the NO_x reduction potential of 45 percent. The NO_x reduction efficiency of SNCR depends upon the temperature, residence time, and ammonia and NO_x concentrations in the flue gas. The injection of ammonia or urea reduce NO_x emissions by 40 to 80 percent depending on the reagent and molar ratio of the reagent and product. This is a significant difference compared to LNB only and LNB with indirect firing.

IDEM selects SNCR as NO_x BART for the cement kiln source category. This includes cement kilns with no add-on NO_x controls and those with LNB. Although LNB are the next best retrofit technology for cement kilns with no add-on NO_x controls, these devices have been rejected as BART by the EPA as shown in the BART evaluations collected by Region 8 in Appendix C of the Indiana RH SIP for the Second Implementation Period Nitrogen Oxides and Sulfur Dioxide Four-Factor Analysis For Cement Kilns document in Appendix G of this document and replaced by the cement manufacturing industry as the standard NO_x emissions reduction control measure for all cement kiln designs. This is demonstrated by the number of new preheater/precalciner cement kiln designs with SNCR for NO_x control (LADCO 2015).

The advantages of using SNCR are the following for most cement kiln designs:

- Reduced NO_x, and
- Possibility to use petroleum coke with current NO_x limits.

The disadvantages of using SNCR are the following for most cement kiln designs:

- Higher than average CO,
- Ammonia emissions observed during raw mill offline periods, and
- Ammonia emissions may occur over longer periods of time when the raw mill system is operational.

10.7.2 Source Category Reasonable Level of Control for SO₂ Emissions

Sulfur dioxide emissions from cement kilns are primarily derived from sulfur in the kiln feed as described in Section 10.4 on page 103. The form of the sulfur dictates the location in the kiln where the SO₂ generation takes place. SO₂ scrubbing technologies are an efficient way to reduce SO₂. DSI systems are mechanically simple and consist of much fewer moving parts and ancillary systems compared to other scrubbing technologies such as wet scrubbers and spray dryer absorbers.

DSI systems are available for all kiln types. Table 10-3 on page 104 reports a 25-50 percent SO₂ reduction potential for DSI, dependent on fuels burned, kiln use, and kiln configuration. DSI technology was originally designed to reduce the amount of sulfur trioxide and acid gas emissions at sources such as coal-fired boilers. Since the amount of SO₂ removal achieved by DSI has always been less than other, more effective means of SO₂ removal (such as, wet, or dry FGD systems specifically designed for sulfur dioxide removal), the technology was not previously marketed for SO₂ removal. However, recent regulatory drivers, such as the EPA Mercury and Air Toxics Rule for EGUs, have created renewed interest in DSI as a means of SO₂ removal due to the considerably lower capital costs of DSI compared to the more conventional wet or dry FGD systems. For this reason, SO₂ removal efficiency for these devices have improved.

IDEM selects DSI as SO₂ BART for the cement kiln source category because it is the next best retrofit technology for cement kilns with no add-on controls. With the installation of a DSI system, there is a high potential that footprint/physical space would be significantly impacted and inclusion of a baghouse in addition to the DSI system may be necessary.

11.0 FOUR-FACTOR ANALYSES FOR INDIANA'S CEMENT KILNS

Cement is manufactured through a closely controlled chemical combination of calcium, silicon, aluminum, iron, and other ingredients. Common materials used to manufacture cement is limestone, clay, slag, shale, silica sand, and iron ore. These ingredients, when heated at high temperatures in a cement kiln form a rock-like structure called clinker, which is subsequently ground to a fine powder, and thoroughly intermixed to form a homogeneous mixture commonly thought of as cement. The rotary kilns, where clinker is chemically formed, are long, steel, cylindrical shells lined with a special refractory brick to withstand the severe effects of abrasion and high temperatures. Cement kilns are slightly inclined, so the kiln feed introduced in the back end of the kiln ("cold" end) is able to travel to the front end ("hot" end) and be transformed chemically along the path. The kiln length serves as the calcining zone where at the lower end of the kiln, the decomposition reactions of the carbonates occur.

11.1 Lehigh Cement Company, LLC

At the Mitchell plant, Lehigh Cement Company operates three long dry rotary kilns to produce Portland cement. Kilns #1 and #2 were constructed in 1959 as long dry kilns and modified to one-stage preheater kilns in July 2003 with a heat input rate of 118 million Btu per hour and a nominal production rate of 38 tons per hour. Kiln #3 was constructed in 1974 as a one-stage preheater kiln with a heat input rate of 118 million Btu per hour and nominal production rate of 43 tons per hour.

The front end of the cement kiln is where the fuel is introduced, which for the cases of the three cement kilns at Mitchell, is a combination of pulverized coal and/or NG. Heat from the firing of fuel is carried by the air stream being drawn through the process and used to heat the kiln feed. For Mitchell's kilns, the one-stage cyclone-type preheater improves the kiln's thermal efficiency and productive capacity, allowing for some counter-current heat transfer to occur between the gas stream and the fresh kiln feed before it reaches the front end of the kiln. Compared to the simple rotary kiln (long dry process) without preheater vessels, the heat transfer rate is higher, the degree of heat utilization is greater, and the process time is reduced in the Mitchell kilns due to the intimate contact of the solid particles with the hot gases in the preheater vessels.

Oxygen levels are monitored in the kiln system as an indication of complete combustion and to ensure fuel efficiency. Typical oxygen levels and temperatures at the kiln inlets and outlets are provided in Table 11-1 below.

Table 11-1 Lehigh Cement Company Kilns Operations Design Parameters

Location	Oxygen (%)	Temperature (°F)
Kiln #1, #2, and #3 Inlets	Not Measured	1000-1400
Kiln #1, #2, and #3 Outlets	2-4	2700-3000

11.1.1 NO_x Emissions and Controls at the Mitchell Plant

The largest contributor to overall NO_x emissions is thermal NO_x which results from high temperature combustion. The three Mitchell kilns each have a single cyclone through which raw feed is processed before being introduced to the kiln. While a very small amount of heat transfer occurs in the cyclone, the cyclones do not allow the process to behave like a cement kiln with traditional preheater technology. In reality, the three Mitchell kilns behave like a long dry kiln in terms of fuel efficiency and NO_x formation. None of the three kilns have add-on NO_x control technology installed. To reduce NO_x emissions, the facility relies on good combustion practices and, more recently, reliance on a higher percentage of NG in the annual fuel mix.

11.1.2 SO₂ Emissions and Controls at the Mitchell Plant

The three Mitchell kilns have minimal add-on SO₂ control devices. All three kilns have dry sorbent injection DSI systems through which lime is processed and introduced to the kiln systems. The DSI systems are used minimally and were

installed for the purposes of reducing HCl emissions at times. However, introduction of lime to the kiln process also has the co-benefit of reducing SO₂ emissions.

There are mechanisms inherent to the cement manufacturing process, in particular the calcination processing the production of clinker, which act to control SO₂ emissions. The calcination process in a cement kiln is designed to convert calcium carbonate CaCO₃ into lime CaO. This produces a lime-rich environment that is ideal for the scrubbing of any SO₂ present in the combustion gases by allowing the SO₂ to react to form CaSO₃ and CaSO₄ that, in turn are incorporated into the clinker. CaSO₄ is very stable as a solid, thus the majority of SO₂ formed from combustion in the kiln process exits the kiln in the clinker as CaSO₄ rather than in the exhaust gas as SO₂.

11.1.3 NO_x and SO₂ Emissions Trends at the Mitchell Plant

NO_x and SO₂ emissions from Mitchell's three kilns follow the same trend as the throughput for the 11-year period from 2008 to 2018. Reported annual NO_x and SO₂ emissions and throughputs for the Mitchell kilns are combined in Table 11-2 on the following page. The bar graphs in Graphs 11-1 and 11-2 on page 115 and 116, respectively were developed using the emissions and throughput information in Table 11-2.

The first graph in Graph 11-1 shows a similar trend for NO_x and SO₂ emissions as the trend for throughput in the second graph in Graph 11-2 for the Mitchell kilns. This indicates that NO_x and SO₂ emissions for the cement kilns are driven by cement production and are a direct result of the type and amount of fuel and raw meal used for cement production. Graphs 11-1 and 11-2 show that NO_x and SO₂ emissions increased in 2010 while throughput decreased. Then in 2011, NO_x and SO₂ emissions decreased while throughput increased.

The Mitchell kiln units are subject to the Standards of Performance for Portland Cement Plants, 40 CFR 60, Subpart F for facilities that commenced construction or modification after August 17, 1971, but on or before June 16, 2008 but the NO_x and SO₂ emission limitations in Subpart F apply to kiln units that commenced construction or modification after 2008. There are no NO_x or SO₂ emission limitations applicable to the existing three kilns in the NESHAPs or NSPS for Portland cement plants, therefore, the anomalies in 2010 and 2011 cannot be attributed to these regulations.

A review of the source's Part 70, Title V Operating permits revealed that in 2008 the Lehigh Cement Company submitted a letter informing IDEM of its intention to conduct a temporary operation and experimental trial. In 2008, the source was issued a Title V Temporary Operation permit and an extension permit in 2009, related to the use of engineered fuel in kiln #1. The temporary operation was conducted in two phases over an approximate two-year period that began in 2010, which suggests that the anomalies in 2010 and 2011 can be attributed to the temporary operation and experimental trial. In 2013, the company was issued a Title V Administrative Amendment permit to allow all three kilns at Mitchell to use additional alternative

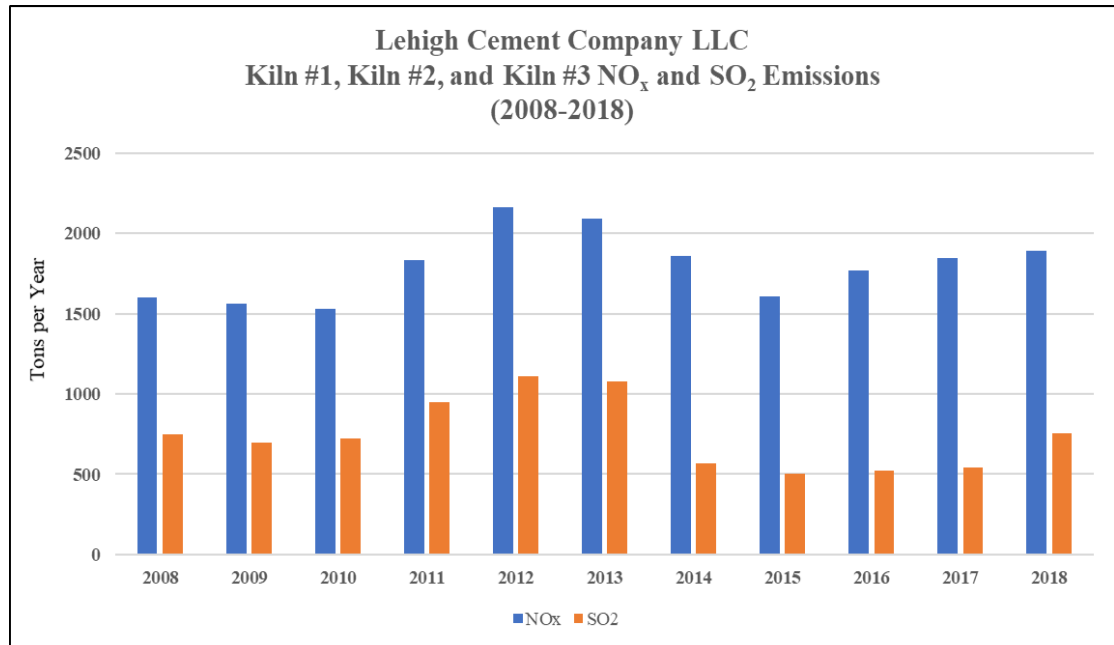
fuels. NO_x or SO₂ emission are not regulated under the NESHAPs for Hazardous Waste Combustors, 40 CFR 63, Subpart EEE.

Table 11-2 Lehigh and Lone Star Kilns NO_x and SO₂ Emissions and Throughput

Inventory Year	LEHIGH CEMENT COMPANY, LLC			LONE STAR INDUSTRY, INC DBA BUZZI UNICEM		
	Actual Throughput	NO _x Emissions (ton/yr)	SO ₂ Emissions (ton/yr)	Actual Throughput	NO _x Emissions (ton/yr)	SO ₂ Emissions (ton/yr)
2008	616064	1603.62	745.97	1274148	1726.36	500.46
2009	577076	1563.28	698.58	1318451	2012.33	410.76
2010	610039	1527.39	719.56	1122421	1763.10	208.76
2011	563803	1833.23	949.57	1083141	1746.21	167.76
2012	676583	2162.70	1108.30	1090071	2118.19	158.82
2013	655246	2089.94	1075.41	934789	1409.51	138.29
2014	636948	1859.00	569.02	1024609	1317.91	174.63
2015	541656	1609.14	501.92	1230046	1397.32	148.75
2016	665975	1767.30	519.38	1219236	1580.96	138.86
2017	696917	1847.29	540.42	1159966	1686.35	168.69
2018	599142	1889.19	753.27	1091362	1713.20	104.30

Note: Reported emissions from the sources' emission statements in accordance with Title V reporting requirements (328-IAC-2-6)

Graph 11-1 Lehigh Cement Company Kilns NO_x and SO₂ Emissions



Graph 11-2 Lehigh Cement Company Kilns Throughput



11.2 Mitchell Plant Four-Factor Analysis for Chosen NO_x and SO₂ BART

On June 27, 2019, the Lehigh Cement Company was issued a Title V Significant Source Modification permit to construct a new pyroprocessing system consisting of one five stage preheater, calciner, rotary kiln. The latest estimate on completion of this project is the first quarter of 2023, based on an article in Lehigh Hanson Company website published on April 29, 2021. Fuels to be used in the pyroprocessing consist of coal, coke, NG, fuel oil, and non-hazardous alternative fuels (e.g., chipped and whole tires, engineered fuels, and dried biosolids). The preheater design includes multiple cyclone preheater vessels in which hot exhaust gases from the rotary kiln pass upward through the downward-moving raw materials in the preheater vessels. The first fuel introduction points are within the calciner/loop duct/kiln riser duct area, which is designed to create a combustion atmosphere that reduces NO_x emissions from the kiln. SNCR will also be utilized to further control NO_x emissions from the pyroprocessing system. SNCR will inject aqueous ammonia in various areas of the kiln riser duct, calciner and loop duct to control NO_x emissions.

Calcined material from the preheater and calciner will enter the kiln where the kiln exhaust gases exit the kiln. As the calcined material migrates through the kiln, its temperature will rise and result in additional chemical reactions until clinker is formed near the discharge end of the kiln. The kiln burner or second fuel source will be located at the clinker discharge end of the kiln. The kiln burner will be the heat source for increasing the temperature of the calcined material and its transformation into clinker.

The preheater exhaust gases will exit the top stage of the preheater and will be cooled and used to supply drying heat in the raw mill or be vented to the main dust collector. In addition to the inherent scrubbing achieved when raw feed interacts with kiln exhaust gases

in the inline raw mill, the future system will be equipped with a DSI system in order to control SO₂ emissions. A dry sorbent will be introduced prior to the main dust collector. The sorbent will be metered from the storage bin and delivered to the injection point by a pneumatic system.

SNCR reduces NO_x emissions to elemental nitrogen, N₂, by injecting a nitrogen containing compound, such as ammonia or urea, into the exhaust gas. SNCR reactions occur at a high temperature, which exists in a cement kiln. The optimum range is between 800 and 1000 °C, which can be achieved by most kilns due to the high temperatures necessary to cause calcination. The temperature of the exhaust gas of a preheater/precalciner kiln system is appropriate for SNCR use. The reaction also requires proper retention time and gas mixing within this temperature range for the reduction to take place. SNCR is a proven technology in the US, with a large fraction of the plants using SNCR.

Based on the fact that the Lehigh Cement Company has begun construction and the new kiln will replace the three existing kilns, IDEM does not believe that a four-factor analysis for the Mitchell plant adds value to the cement kiln four-factor analysis and, therefore, is not necessary. The chosen NO_x and SO₂ reasonable level of controls for the cement kiln source category are planned for the new cement kiln units at Mitchell. The new kiln units will be subject to the new NSPS for Portland cement plants. Therefore, the NO_x and SO₂ and emission limitations listed in Table 11-3 below are applicable to the kiln units.

Table 11-3 New Source Performance Standards NO_x and SO₂ Emission Limits

Pollutant	Emission Limit	Averaging Period
NO _x	1.5 lbs/ton clinker	averaged over 30 days
SO ₂	0.4 lbs/ton clinker	averaged over 30 days

11.3 Lone Star Industries, Inc. dba Buzzi Unicem USA

At the Greencastle plant, Lone Star Industries operates one semi-dry kiln. This cement kiln type is unique in its design and operation and is one of only two semi-dry kilns in operation in the United States. Like a traditional long wet cement kiln, raw materials are ground and blended with water to form a slurry for feed to the kiln. However, unlike a traditional wet plant, in a semi-dry process like Greencastle's, the slurry is injected into a crusher/drier that flashes off the water content of the slurry and renders a dried material that is then transported to a preheater/precalciner. Typical oxygen levels and temperatures for various locations in the process are provided in Table 11-4.

Table 11-4 Lone Star Kiln Operations Design Parameters

Location	Oxygen (%)	Temperature (°F)
Calciner Outlet/ First Stage Inlet	Not Measured	1550-1650
First Stage Outlet/ Crusher-Dryer Inlet	Not Measured	1600-1700
Crusher-Dryer Outlet	3-4	400-500

The pre-heater/pre-calciner Portland cement kiln was originally constructed in 1966 and modified to the semi-dry system in 2000. The semi-dry kiln system includes a calciner tower with staged combustion and a rotary kiln with a combined nominal rated clinker capacity of 208 tons per hour. The semi-dry kiln system, uses coal and the following supplemental fuels:

- Liquid and solid hazardous waste fuel at a maximum rate allowed by the NESHAP for Hazardous Waste Combustors, 40 CFR 63, Subpart EEE,
- plastic chips, carpet fibers, paper products, wood chips, chipped tires, toner, cosmetics, seed corn, and oil absorbent material including oil filter fluff,
- petroleum coke, and
- distillate fuel for burner startup activities,

11.3.1 NO_x Emissions and Controls at the Greencastle Plant

The largest contributor to overall NO_x emissions is thermal NO_x which results from high temperature combustion. To reduce NO_x emissions, the facility utilizes staged combustion and is equipped with multi-channel low-NO_x burners in both the kiln and calciner. Staged combustion is accomplished by introducing fuel into an expanded portion of the kiln riser duct. Since the kiln exit gas has a relatively low oxygen content available for combustion, a high temperature reducing zone is created in the riser duct. These conditions render less oxygen available for chemical reaction with the nitrogen present and the potential for NO_x formation is reduced as a result.

The Greencastle plant also uses liquid hazardous waste to provide a considerable portion of the heat requirement to produce clinker. The use of liquid hazardous waste fuel (LHWF) as a substitute for traditional fossil fuels in both the kiln and the calciner also has a substantial effect of lowering NO_x emissions, due to the water content of the LHWF. Water injection is a well-established mechanism for controlling thermal NO_x emissions. LHWF typically contains approximately up to 18% moisture. The LHWF is injected into both the kiln and calciner burner systems, where the inherent moisture has the effect of cooling the flame and reducing the formation of thermal NO_x. For cyclone boilers that generate high levels of thermal NO_x, reductions of 22% have been demonstrated and higher reductions are possible. Industry experience has shown up to a 50% control efficiency for water injection into the burning zone of a cement kiln.

11.3.2 SO₂ Emissions and Controls at the Greencastle Plant

The Greencastle kiln has no add-on control devices for the control of SO₂. However, there are mechanisms inherent to the cement manufacturing process, in particular the calcination processing in the production of clinker, which act to control SO₂ emissions. The calcination process in a cement kiln is designed to convert calcium carbonate (CaCO₃) into lime (CaO). This produces a lime-rich environment that is ideal for the scrubbing of any SO₂ present in the combustion gases by allowing the SO₂ to react to form CaSO₃ and CaSO₄ that, in turn are incorporated into the clinker. CaSO₄ is very stable as a solid, thus the majority of SO₂ formed from combustion in the kiln process exits the kiln in the clinker as CaSO₄ rather than in the exhaust gas as

SO₂. An additional scrubbing mechanism occurs in the flash drier where hot gases from the top of the tower are used to flash dry the slurry in the crusher/dryer making calcium in the raw materials available to absorb SO₂, comparable to in-line raw mills which AP-42 indicates have absorption capabilities up to 95%. The overall effect of these inherent mechanisms in the Greencastle kiln system is evidenced by the low annual SO₂ emissions from the Greencastle plant.

11.3.3 NO_x and SO₂ Emissions Trends at the Greencastle Plant

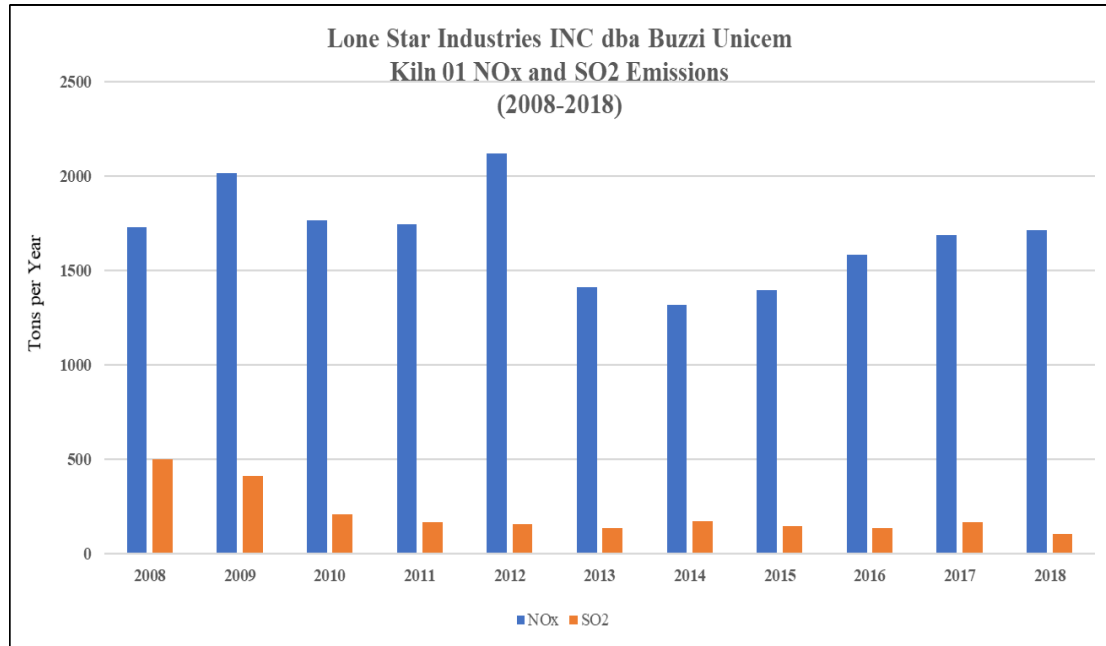
The bar graphs in Graphs 11-3 and 11-4 on the following page show the emissions and throughput trends for the Greencastle cement kiln over the 11-year period from 2008 to 2018. Reported annual NO_x and SO₂ emissions and throughputs for the Greencastle kiln are listed in Table 11-2 on page 115. Graphs 11-3 and 11-4 on the following page were developed using the emissions and throughput information in Table 11-2.

NO_x and SO₂ emissions from the Greencastle kiln shown on the bar graph in Graph 11-3 mostly follow the same trend as the kiln's throughput in Graph 11-4. This indicates that NO_x and SO₂ emissions from the Greencastle kiln are influenced by clinker production. Since SO₂ emissions are primarily driven by the amount of sulfur in the kiln feed, emissions correlate to the amount of kiln feed used.

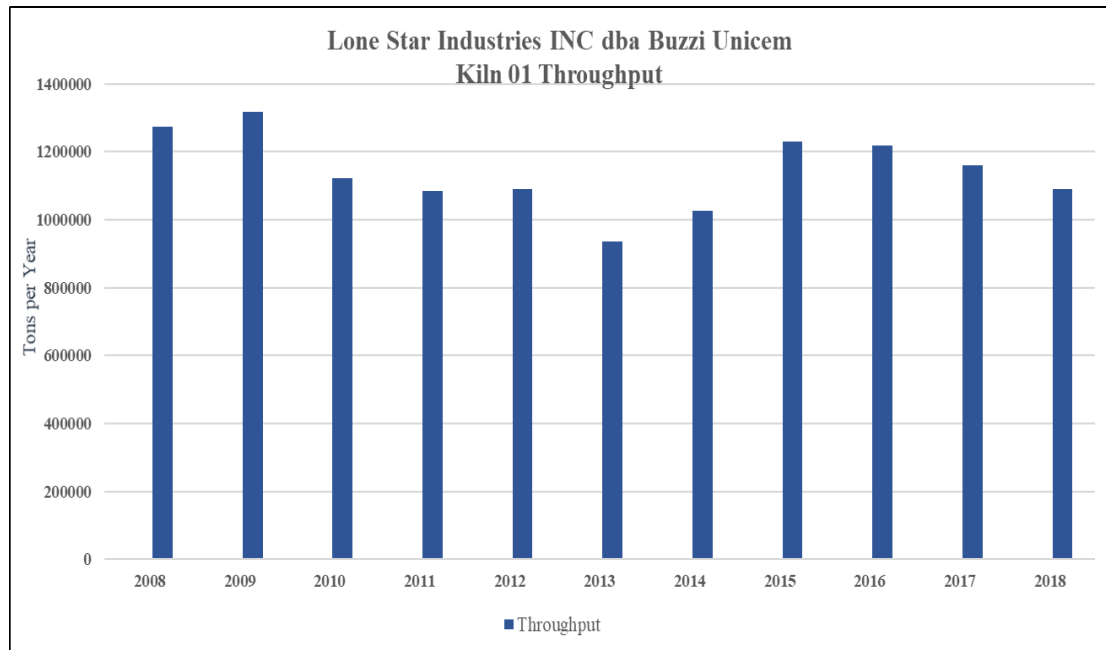
The SO₂ bar graph shows that SO₂ emissions from the Greencastle kiln are low throughout the entire 11-year period. This is likely due to the low sulfur in the raw materials as well as the inherent scrubbing effect of the crusher/dryer. NO_x emissions tend to correspond to changes in production since cement kiln NO_x emissions are predominantly thermal NO_x formation from the combustion of fuel.

The Greencastle kiln units are subject to the Standards of Performance for Portland Cement Plants, 40 CFR 60, Subpart F for facilities that commenced construction or modification after August 17, 1971, but on or before June 16, 2008. However, the NO_x and SO₂ emission limitations in Subpart F apply to kiln units constructed or modified after 2008. Therefore, the anomalies shown in the NO_x and SO₂ emissions trends cannot be attributed to the NESHAPs or NSPS for Portland cement plants.

Graph 11-3 Lone Star Industries Kiln NO_x and SO₂ Emissions



Graph 11-4 Lone Star Industries Kiln Kilns Throughput



11.4 Greencastle Plant Four-Factor Analysis for Chosen NO_x and SO₂ BART

11.4.1 Cost of Compliance for Chosen NO_x and SO₂ BART

IDEM relied on a cost estimate provided by Lehigh Cement to develop the cost effectiveness analysis in Appendix D of the Indiana RH SIP for the Second Implementation Period Nitrogen Oxides and Sulfur Dioxide Four-Factor Analysis For

Cement Kilns document. The estimate was based on three cost estimates Lehigh shared when it was considering NO_x and SO₂ retrofit options for its three existing cement kilns. A 2018 estimate to retrofit the existing kilns (the estimated costs are for one kiln) at the Mitchell plant with SNCR systems for NO_x control, a 2016 estimate to retrofit the existing kilns (the estimated costs are for one kiln) with DSI systems for SO₂ control, and a 2019 estimate to install the new kiln with SNCR and DSI were used to estimate the costs to retrofit the kiln at Lone Star Industries with SNCR and DSI systems.

The estimated capital costs to retrofit the Greencastle kiln with SNCR and DSI systems were carved out of the estimate to install the new kiln with SNCR and DSI systems at the Mitchell plant. The direct and indirect capital costs to retrofit an existing kiln with SNCR and DSI systems are conservative estimates that are not specific to the Greencastle plant kiln, however the estimated capital costs offer a base to build upon. A 2018 proposed estimate to construct a SCR system for SO₂ control in Appendix E of the Indiana RH SIP for the Second Implementation Period Nitrogen Oxides and Sulfur Dioxide Four-Factor Analysis For Cement Kilns document was included in Mitchell's Title V PSD Significant Source Modification permit (SSM permit #093-40198-00002) to construct the new kiln submitted on June 27, 2019. The capital recovery factor found in the SCR cost estimate was used to calculate the total annualized capital costs for the SNCR and DSI systems in the cost estimate for the cost effectiveness analysis.

The list of line items in the SCR estimate were used to develop the line-item list of direct and indirect operations and maintenance costs to retrofit the Greencastle cement kiln with SNCR and DSI. The 2016 DSI cost estimate, the 2018 SNCR cost estimate, and the 2018 SCR cost estimate were all used to estimate the operations and maintenance cost items in the Greencastle estimate for the cost effectiveness analysis.

The estimated total annualized capital costs to install each retrofit system plus the estimated total annual operations and maintenance costs to operate each retrofit system for the Greencastle cement kiln were used to calculate the total annual costs, which were, in turn, were used to calculate the cost effectiveness for both systems. IDEM went with conservative control efficiencies for the SNCR (40%) and DSI (45%), as compared to the control efficiency ranges for each device in Table 10-1 on page 96 and Table 10-3 on page 104. The cost effectiveness per ton of pollutant removed analysis resulted in a cost of \$873 per ton for a SNCR retrofit and \$8,142 per ton for a DSI retrofit as shown in Appendix D of the Indiana RH SIP for the Second Implementation Period Nitrogen Oxides and Sulfur Dioxide Four-Factor Analysis For Cement Kilns document. These results are in line with the cost effectiveness results in Table 10-2 on page 101 and Table 10-4 on page 108.

In spite of the fact that there were no vendor estimates obtained specifically for the Greencastle kiln, IDEM believes that the cost estimates that Lehigh provided are a better source of information than an estimate that Greencastle could obtain for hypothetical SNCR and DSI retrofit installations. These estimates may be flawed,

due to the fact that vendors may not put as much work into developing cost estimates for installations that are not likely to take place as they would for installations that are likely to take place.

In response to the FLM comments related to the Greencastle cost estimate, Buzzi Unicem USA submitted additional information related to Greencastle's cost estimate and cost effectiveness analysis. See Appendix P for specific cost estimate and cost effectiveness details. According to updated information received from Buzzi Unicem, the revised cost effectiveness per ton of pollutant removed analysis resulted in a revised cost of \$1,679 per ton for a SNCR retrofit and \$10,035 per ton for a DSI retrofit.

11.4.2 Time Necessary for Chosen NO_x and SO₂ BART Compliance

The time necessary to install the SNCR and DSI systems is 2 to 3 years for each system depending on a number of variables, such as, time for engineering, construction, and facility preparedness.

11.4.3 Energy and Non-Air Impacts of Chosen NO_x and SO₂ BART

More energy will be consumed by SNCR when the optimum temperature ranges after combustion are not met. DSI consumes more energy when the injection process increases particulate matter in the exhaust gas which causes pressure drops across the PM control devices causing the baghouse filter cake to become saturated with moisture and plug both the filters and the dust removal system. Lone Star does not currently have a bag filter for PM control on the kiln. However, this may become a factor if a bag filter is necessary as a result of installing DSI. For some technologies, a flue gas reheater may be essential to the system thus increasing energy use, also. In addition, the excess particulate collected by PM control devices will need to be disposed of, which increases the facility's solid waste management burdens. Non-air environmental impacts will include solid, liquid, and/or hazardous waste generation and deposition of atmospheric pollutants on land or water.

11.4.4 Remaining Useful Life for Chosen NO_x and SO₂ BART

The SNCR and DSI systems evaluated in the cost effectiveness analysis was based on a 15-year life for each control system. Since the Greencastle cement kiln was modified in 2000, the cement kiln units are considered 20 years old, however due to the kilns actual age, it is assumed for the purpose of this evaluation that the remaining useful life of the cement kiln is 15 years.

12.0 FOUR-FACTOR ANALYSIS SUBMITTALS FOR INDIANA'S NON-ELECTRIC GENERATING UNITS

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 SO₂ emission units at each selected source. The emission units identified for NO_x and/or SO₂ four-factor evaluation were chosen based on the units' reported 2018 NO_x and SO₂ emissions. IDEM compared the emission units reported 2018 NO_x and SO₂ emissions to the units' NO_x and SO₂

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 SO₂ emitters. No specific cutoff value or percentage was used to identify a facility's highest NO_x and SO₂ 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. These four-factor analysis submittals are attached as appendices for reference.

Sections 13.0 through 17.0 in this document were taken from the "Indiana RH SIP 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" document, dated May 18, 2021. This document is a standalone version of Indiana's Four-Factor Analysis for Iron and Steel Mills, Aluminum Production and Plastics Manufacturing Plants and Electric Services Plant, which can be found in Appendix I.

13.0 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 in the appendices to the Indiana RH SIP 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 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.

13.1 Cleveland-Cliffs Steel, LLC - Indiana Harbor East (Indiana Harbor East) NO_x and SO₂ Emissions and Controls

Cleveland-Cliffs Steel, LLC 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, Indiana 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 SO₂ emissions and existing control measures for each emission unit chosen for four-factor analysis evaluations are described in this section.

Table 13-1 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 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.

SO₂ 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 SO₂ 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 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 SO₂ 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 SO₂ 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 SO₂ upon contact with ambient air during the casting process. Casting emissions are collected and routed to one of two casthouse baghouses for particulate control. Emissions from slag runners and pits outside of the casthouse are fugitive-in-nature (i.e., not emitted from a stack).

The No. 7 Blast Furnace Flares produce NO_x and SO₂ 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 SO₂ emission control measures.

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 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 SO₂ 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 SO₂ emission control measure for these unit. The use of a preheater to preheat limestone feed using residual heat in combustion gases reduces NG SO₂ emissions by reducing fuel requirements. Furthermore, the production of lime that is in contact with combustion gases inherently scrubs combustion gases of SO₂, further reducing SO₂ 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 SO₂ emissions through oxidation of sulfur compounds present in the raw materials (iron byproduct/recycled materials, coke breeze, etc.) and NG fuel. As an SO₂ 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 SO₂ limit.

13.2 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 13-2 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.

13.2.1 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 of the company's four-factor analysis submittal. 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.

13.2.2 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.

13.2.3 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.

13.2.4 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.

13.2.5 NO_x Emissions Trends at the Indiana Harbor East Facility

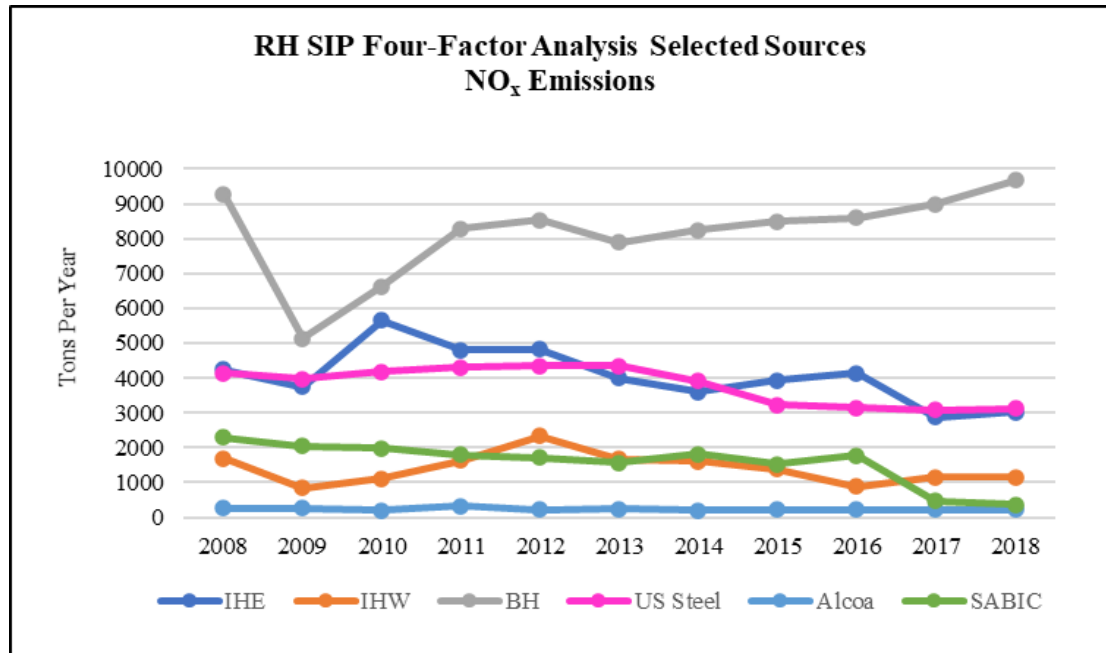
Indiana Harbor East facility-wide NO_x emissions show a downward trend over the 11-year evaluation period as reflected in Table 13-3 and Graph 13-1 on the next page

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 13-1 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 13-3 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 13-1 Indiana Selected Sources 2008-2018 NO_x Emissions Trends

13.2.6 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 J of this document.

In response to the FLM comments related to the Indiana Harbor East cost estimate, Cleveland Cliffs Steel, LLC submitted additional information related to Indiana Harbor East's cost estimate; however, none of the cost effectiveness costs per ton of NO_x removed values changed. See Appendix Q for Cleveland Cliffs Steel specific four-factor analysis responses related to this facility.

13.3 Indiana Harbor East Four-Factor Analysis of Potential SO₂ Control Options

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

The RBLC search and search of air permits for iron and steel mills and similar sources for boiler SO₂ 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 SO₂ emission control measure and there are no additional SO₂ 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 SO₂ emission control measures beyond what is currently installed and operated.

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, casthouse, and flare SO₂ 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 SO₂ emission control measure. The AK Steel 2014 Dearborn BACT concluded that additional SO₂ 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 SO₂ emission control measures are technically feasible for blast furnace stoves, casthouses, and flares.

Therefore, there are no additional SO₂ 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 SO₂ emission control measures beyond what is currently installed and operated for these emission units.

Lime Plant No. 1 and No. 2

The RBLC search and search of air permits for iron and steel mills and similar sources for lime plant SO₂ 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 SO₂ 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 SO₂ 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 SO₂ emission control measures. So, there are no additional SO₂ 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 SO₂ 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 SO₂ emission control measure. The RBLC search and search of air permits for iron and steel mills and similar sources for Sinter Plant SO₂ 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 SO₂ is absorbed by the slurry, forming CaSO₃/CaSO₄. The liquid-to-gas ratio is such that the water evaporates before the droplets reach the bottom of the tower. The dry solids are collected with a fabric filter downstream. Dry sorbent (pulverized lime or limestone) is directly injected into the duct upstream of a fabric filter. SO₂ reacts with the sorbent, and the solid particles are collected by the fabric filter. Further SO₂ 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 SO₂ that is captured by the scrubber would need to be neutralized and treated as wastewater. Since the associated issues are not present and the SO₂ emission control performance is generally comparable with SDAs or DSI (dry controls), wet scrubbing was excluded from the reasonable set of SO₂ emission control measures. SDAs installation and DSI for the Sinter Plant Windbox are evaluated as SO₂ emission control measures.

Table 13-4 Indiana Harbor East Emission Units SO₂ 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	

13.3.1 Cost of Compliance for Potential SO₂ Control Options

Indiana Harbor East completed cost estimates for spray dryer installation and DSI on the Sinter Plant Windbox. Cost summary spreadsheets for the SO₂ emission control measures are provided in Appendix A of the Indiana RH SIP Nitrogen Oxides and Sulfur Dioxide Four-Factor Analysis For Iron and Steel Mills, Aluminum Production and Plastics Manufacturing Plants and Electric Services Plant document and in Appendix J in this document. 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 an 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 an 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 of the Indiana RH SIP Nitrogen Oxides and Sulfur Dioxide Four-Factor Analysis for Iron and Steel Mills, Aluminum Production and Plastics Manufacturing Plants and Electric Services Plant document and in Appendix J of this document.

13.3.2 Time Necessary for Potential SO₂ 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.

13.3.3 Energy and Non-Air Impacts of Potential SO₂ 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 of the Indiana RH SIP Nitrogen Oxides and Sulfur Dioxide Four-Factor Analysis for Iron and Steel Mills, Aluminum Production and Plastics Manufacturing Plants and Electric Services Plant document and in Appendix J of this document. The SDA and DSI would generate additional solid waste that would require disposal in permitted landfills.

13.3.4 Remaining Useful Life for SO₂ 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.

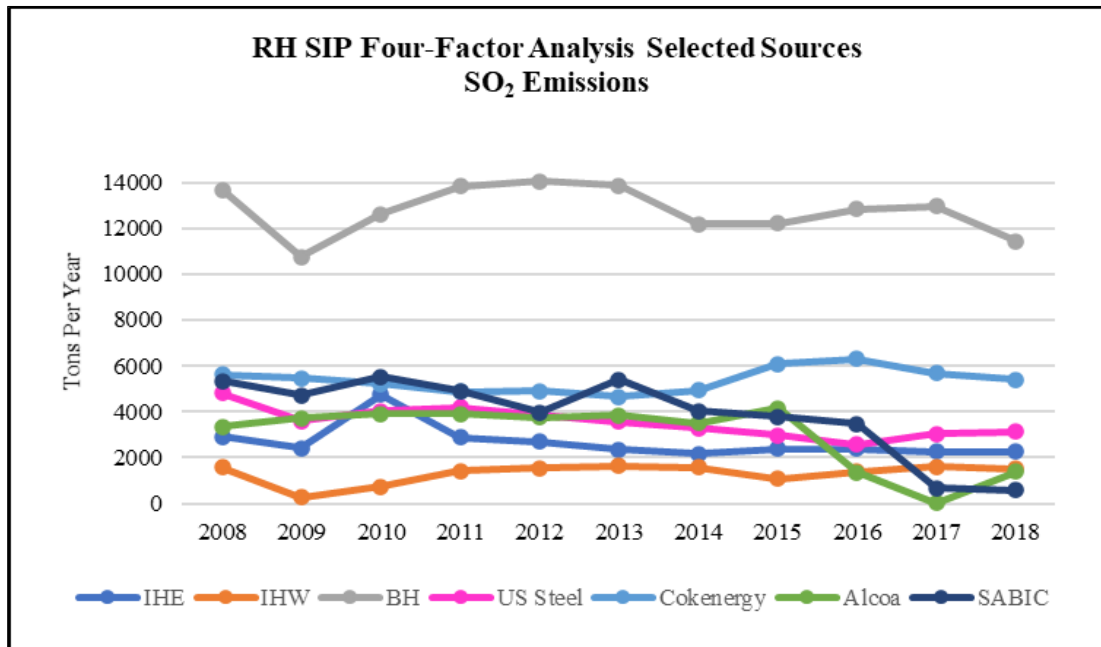
13.3.5 SO₂ Emissions Trends at the Indiana Harbor East Facility

Indiana Harbor East facility-wide SO₂ emissions listed in Table 13-5 below and shown in Graph 13-2 on the following page show the same downward trend over the 11-year evaluation period. As described in Section 13.2.5 and illustrated on the line graph in Graph 13-2 on the next page, there was a significant decrease in SO₂ emissions in 2009 due to an economic downturn that resulted in reduced production rates during the year. The overall SO₂ emissions from the facility decreased 23% from 2008 to 2018.

Table 13-5 Indiana Four-Factor Analysis Selected Sources 2008-2018 SO₂ 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 13-2 Indiana Selected Sources 2008-2018 SO₂ Emissions Trends



13.3.6 Indiana Harbor East Reasonable Level of Control for SO₂ Emissions

The reasonable set of SO₂ 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 SO₂ removed for the SDA and \$38,200 per ton of SO₂ removed for the DSI system. The Cost Effectiveness and Cost Estimate spreadsheets are attached in Appendix A of the Indiana RH SIP Nitrogen Oxides and Sulfur Dioxide Four-Factor Analysis for Iron and Steel Mills, Aluminum Production and Plastics Manufacturing Plants and Electric Services Plant document and in Appendix J of this document.

In response to the FLM comments related to the Indiana Harbor East cost estimate, Cleveland Cliffs Steel, LLC submitted additional information related to Indiana Harbor East's cost estimate; however, none of the cost effectiveness costs per ton of SO₂ removed values changed. See Appendix Q for Cleveland Cliffs Steel specific four-factor analysis responses related to this facility.

13.4 Cleveland-Cliffs Steel - Indiana Harbor West (Indiana Harbor West) NO_x and SO₂ 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 SO₂ four-factor analyses in IDEM's RFI are listed in the table on the following page and the sources of each unit's NO_x and SO₂ emissions and existing control measures are described in this section.

Table 13-6 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ emission control measures.

13.5 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-NO_x 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 13-7 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.

13.5.1 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 13-3 on page 134. The line graph shown in Graph 13-1 on page 134 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.

13.5.2 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.

13.6 Indiana Harbor West Four-Factor Analysis of Potential SO₂ 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 SO₂ 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 SO₂ emission control measure.

There are no additional SO₂ 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 SO₂ 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 SO₂ 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 SO₂ emission control measure. The AK Steel Dearborn 2014 PSD Permit did not require additional SO₂ emission control measures and the Nucor 2010 BACT determined that other than the low-sulfur fuels (BFG and NG), no additional add-on SO₂ emission control measures are technically feasible.

Therefore, there are no additional SO₂ 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 SO₂ 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 SO₂ emission control measures, either. The AK Steel Dearborn 2014 PSD Permit did not require additional SO₂ emission control measures and the Nucor 2010 BACT stated that there are no feasible SO₂ emission control measures because of the corresponding low SO₂ concentration (~4 ppm SO₂) and high exhaust flow rate.

Therefore, there are no additional SO₂ 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 SO₂ 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 SO₂ emission control measures. Therefore, there are no additional SO₂ 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 SO₂ emission control measures beyond what is currently installed and operated for these emission units.

Table 13-8 Indiana Harbor West Emission Units SO₂ 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.

13.6.1 SO₂ Emissions Trends at the Indiana Harbor West Facility

Indiana Harbor West have achieved some facility-wide SO₂ 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 13-2 on page 140 show a decrease in facility wide SO₂ emissions in 2009 due to an economic downturn that resulted in reduced production rates. Indiana Harbor West reduced SO₂ emissions by 16% over the 11-year evaluation period according to Table 13-5 on page 139.

13.6.2 Indiana Harbor West Reasonable Level of Control for SO₂ Emissions

The evaluation for SO₂ emission control measures determined that there are no reasonable SO₂ emission control measures beyond what is currently installed and operated for the emission units identified; therefore, no cost effectiveness analysis was conducted.

13.7 Cleveland-Cliffs Burns Harbor, LLC (Burns Harbor) NO_x and SO₂ 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 and the sources of each unit's NO_x and SO₂ emissions and existing control measures are described in this section.

Table 13-9 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 SO₂ 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 SO₂ 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. SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ upon contact with ambient air during the casting process. Casting emissions are collected and routed to one of two casthouse baghouses for particulate control. Emissions from slag runners and pits outside of the casthouse are also fugitive-in-nature.

The Blast Furnaces C and D Flares produce NO_x and SO₂ 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 SO₂ emission control measures.

13.8 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 13-10 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.

13.8.1 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 13-3 and Graph 13-1 on page 134 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 Figure 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 13-1 illustrates an overall 4% increase in facility-wide NO_x emissions from 2008 to 2018.

13.8.2 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.

13.9 Burns Harbor Four-Factor Analysis of Potential SO₂ Control Options

Battery Nos. 1 and 2

The RBL search and search of air permits for iron and steel mills and similar sources for coke oven battery SO₂ 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 SO₂ emission control measures.

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

However, wet scrubbers produce substantial amounts of sulfate-impacted wastewater which requires additional wastewater treatment processes at the facility. As such, wet scrubbers are excluded from the reasonable set of SO₂ emission control measures for the Battery Nos. 1 and 2.

Burns Harbor identified coke oven gas treatment through the installation of a desulfurization plant to be part of the reasonable set of SO₂ emission control measures for further evaluation. Burns Harbor identified installation of SDAs or a desulfurization plant to be part of the reasonable set of SO₂ 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 SO₂ 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 SO₂ emission control measure. Burns Harbor identified installation of coke oven gas desulfurization to be part of the reasonable set of SO₂ emission control measures for the Clean Coke Oven Gas Export Line for further evaluation. Coke oven gas desulfurization for the Clean Coke Oven Gas Export Line is evaluated as a SO₂ 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 RBL search and search of air permits for iron and steel mills and similar sources for coke oven battery flares SO₂ 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 SO₂ emission control measures for further evaluation. Since a desulfurization plant affects all of the downstream coke oven gas consumers, including the Clean Coke Oven Gas Export Line Flare, coke oven gas desulfurization for the Clean Coke Oven Gas Export Line Flare is evaluated as an SO₂ 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 SO₂ 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 SO₂ emission control measure.

It is not appropriate to compare SO₂ 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 SO₂ emission control measures applied to boilers in other industries.

Wet scrubbers can offer SO₂ control performance levels that are generally consistent with spray dryer absorbers and dry sorbent injection. However, wet scrubbers produce substantial amounts of sulfate-impacted wastewater which requires additional wastewater treatment processes at the facility. As such, wet scrubbers are excluded from the reasonable set of SO₂ emission control measures for the Power Station Boiler Nos. 7-12.

Burns Harbor identified coke oven gas treatment through the installation of a desulfurization plant to be part of the reasonable set of SO₂ emission control measures for further evaluation. Since a coke oven gas desulfurization plant affects all of the downstream coke oven gas consumers, including the Power Station Boiler Nos. 7-12, it is addressed separately. 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 SO₂ 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 SO₂ 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 SO₂ emission control measure.

The AK Steel Dearborn 2014 PSD Permit did not require additional SO₂ emission control measures. The 2010 Nucor BACT determined that other than the low-sulfur fuels (BFG and NG), no additional add-on SO₂ emission control measures are technically feasible.

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

The RBLC search and search of air permits for iron and steel mills and similar sources for Blast Furnace Casthouses did not identify any SO₂ emission control measures. AK Steel Dearborn 2014 PSD Permit did not require additional SO₂ emission control measures. The 2010 Nucor BACT stated that there are no feasible SO₂ emission control measures because of the corresponding low SO₂ concentration (~4 ppm SO₂) and high exhaust flow rate.

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

The RBLC search and search of air permits for iron and steel mills and similar sources for Blast Furnace Flares did not identify any SO₂ emission control measures. There are no additional SO₂ emission control measures based on the 2010 Nucor BACT, emission control measures described in the RBLC and air permits for iron and steel mills. As such, the Blast Furnaces C and D Flares have no reasonable set of SO₂ emission control measures beyond what is currently installed and operated for these emission units.

13.9.1 Cost of Compliance for Potential SO₂ 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 SO₂ emission control measures are provided in Appendix A of the Indiana RH SIP Nitrogen Oxides and Sulfur Dioxide Four-Factor Analysis for Iron and Steel Mills, Aluminum Production and Plastics Manufacturing Plants and Electric Services Plant document and in Appendix J of this document.

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 of the Indiana RH SIP Nitrogen Oxides and Sulfur Dioxide Four-Factor Analysis for Iron and Steel Mills, Aluminum Production and Plastics Manufacturing Plants and Electric Services Plant document and in Appendix J of this document.

13.9.2 Time Necessary for Potential SO₂ 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.

13.9.3 Energy and Non-Air Impacts of Potential SO₂ 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 of the Indiana RH SIP Nitrogen Oxides and Sulfur Dioxide Four-Factor Analysis for Iron and Steel Mills, Aluminum Production and Plastics Manufacturing Plants and Electric Services Plant document and in Appendix J of this document. 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.

13.9.4 Remaining Useful Life for SO₂ 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 13-11 Burns Harbor Units SO₂ 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.

13.9.5 SO₂ Emissions Trends at the Burns Harbor Facility

Burns Harbor facility-wide SO₂ emissions show a downward trend over the 11-year evaluation period as reflected in Table 13-5 and Graph 13-2 on pages 139 and 140, 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 13-2 illustrates that Burns Harbor facility-wide SO₂ emissions in 2009 also show the economic downturn that resulted in reduced production rates in the industry during that year. The overall facility wide SO₂ emissions decreased 16% from 2008 to 2018.

13.9.6 Burns Harbor Reasonable Level of Control for SO₂ Emissions

The reasonable set of SO₂ 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 SO₂ 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 of the Indiana RH SIP Nitrogen Oxides and Sulfur Dioxide Four-Factor Analysis for Iron and Steel Mills, Aluminum Production and Plastics Manufacturing Plants and Electric Services Plant document and Appendix J attached):

<u>Emission Unit</u>	<u>Control Measure</u>	<u>Cost Effectiveness</u>
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

In response to the FLM comments related to the Burns Harbor cost estimate, Cleveland Cliffs Steel, LLC submitted additional information related to Burns Harbor's cost estimate; however, none of the cost effectiveness costs per ton of SO₂ removed values changed. See Appendix R for Cleveland Cliffs Steel specific four-factor analysis responses related to this facility.

13.10 United States Steel Corporation - Gary Works (U.S. Steel) NO_x and SO₂ 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 SO₂ emissions and existing control measures are described in this section for each emission unit chosen for four-factor analysis evaluations.

Table 13-12 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

No. 3 Sinter Plant Strands

The No. 3 Sinter Plant agglomerates iron bearing and other materials from various sources to create a raw material feedstock for the blast furnaces that supplements iron ore pellets. The sinter feedstock is thoroughly blended and combusted on each sinter strand by drawing air through the sintered material and into the windboxes. The windboxes exhaust fumes through the two existing control trains which control PM and SO₂ 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 SO₂ 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 Figure 2-1 of the Gary Works four-factor analysis submittal. The exhaust treatment reduces PM and SO₂ 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 SO₂. The dry venturi scrubber with dry limestone addition allows for further removal of the SO₂ 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, O₂, CO and water) and results in actual NO_x emission reductions from fuel savings and minimizes excess air.

13.11 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 over represents 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.

13.11.1 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 of the Indiana RH SIP Nitrogen Oxides and Sulfur Dioxide Four-Factor Analysis for Iron and Steel Mills, Aluminum Production and Plastics Manufacturing Plants and Electric Services Plant document and in Appendix J of this document.

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.

13.11.2 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.

13.11.3 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.

13.11.4 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 13-13 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	

13.11.5 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 13-3 and Figure 13-1 on page 134 as a result of extensive projects, including shutting down three coke battery units. The line graph in Graph 13-1 also shows 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.

13.11.6 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 of the Indiana RH SIP Nitrogen Oxides and Sulfur Dioxide Four-Factor Analysis For Iron and Steel Mills, Aluminum Production and Plastics Manufacturing Plants and Electric Services Plant document and in Appendix J of this document.

In response to the FLM comments related to the Gary Works cost estimate, U.S. Steel Corporation submitted additional information related to Gary Works' cost estimate; however, none of the cost effectiveness costs per ton of NO_x removed values changed. See Appendix S for U.S. Steel specific four-factor analysis responses related to this facility.

13.12 Gary Works Four-Factor Analysis of Potential SO₂ 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 plant sinter strand SO₂ 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 SO₂ emission control measures. A wet scrubber has functionally equivalent SO₂ 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 SO₂ 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 SO₂ emission control measures represent the best SO₂ 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 SO₂ emission control measures. As such, the No. 3 Sinter Plant Sinter Strands have no reasonable set of SO₂ 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 SO₂ emission control measure. The Nucor 2010 BACT determined that other than the low-sulfur fuels (BFG and NG), no additional add-on SO₂ emission control measures are technically feasible. There are also no additional SO₂ 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

SO₂ emission control measures and the existing SO₂ 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 SO₂ 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 SO₂ 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 SO₂ emission control measures beyond what is currently installed and operated for these emission units and the existing SO₂ emission control measures are equivalent to those determined to be BACT in the 2010 Nucor BACT and, therefore, are considered effective emission controls.

Table 13-14 Gary Works Emission Units SO₂ 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.

13.12.1 SO₂ Emissions Trends at the Gary Works Facility

Gary Works facility-wide SO₂ emissions show a downward trend over the 11-year evaluation period as reflected in Table 13-5 and Graph 13-2 on pages 139 and 140, respectively, as a result of extensive projects, including the installation of SO₂ emission control measures on the No. 3 Sinter Plant Sinter Strand. The line graph in Graph 13-2 illustrates Gary Works facility wide SO₂ emissions in 2009 also show the economic downturn that resulted in reduced production rates in the industry during that year. The overall facility wide SO₂ emissions decreased 34% from 2008 to 2018.

13.12.2 Gary Works Reasonable Level of Control for SO₂ Emissions

The evaluation for SO₂ emission control measures determined that there are no reasonable SO₂ emission control measures beyond what is currently installed and

operated for the emission units identified; therefore, no cost effectiveness analysis was conducted.

14.0 CLEAN AIR ACT REGULATION CONTROLLING IRON AND STEEL MILL PLANTS

NO_x and SO₂ 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 SO₂ 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 steel 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 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 SO₂ 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 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 FR² for final NO_x Budget Trading Program SIP approval shows zero reductions to be achieved by the blast furnace gas units.

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.

15.0 PLASTICS MANUFACTURING PLANT

15.1 SABIC Innovative Plastics, Mt. Vernon LLC (SABIC) NO_x and SO₂ 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 SO₂ emissions and existing control measures are described in this section.

Table 15-1 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 may be 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 SO₂ 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 SO₂ emissions at the COGEN stack (i.e., post combustion).

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

The SO₂ 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 CO₂ 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 SO₂ 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 (H₂S), and carbon disulfide (CS₂).

- 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 SO₂ 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 SO₂ 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.

15.2 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 (NH₃) 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 NH₃ 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.

15.2.1 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 of the Indiana RH SIP Nitrogen Oxides and Sulfur Dioxide Four-Factor Analysis for Iron and Steel Mills, Aluminum Production and Plastics Manufacturing Plants and Electric Services Plant document and in Appendix J of this document 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.

15.2.2 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 of the Indiana RH SIP Nitrogen Oxides and Sulfur Dioxide Four-Factor Analysis for Iron and Steel Mills, Aluminum Production and Plastics Manufacturing Plants and Electric Services Plant document and in Appendix J of this document.

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.

15.2.3 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.

15.2.4 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 of the Indiana RH SIP Nitrogen Oxides and Sulfur Dioxide Four-Factor Analysis for Iron and Steel Mills, Aluminum Production and Plastics Manufacturing Plants and Electric Services Plant document and in Appendix J of this document.

Table 15-2 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	

15.2.5 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 13-3 and Graph 13-1 on page 134 as a result of the COGEN facility commencement of operations in 2016. The line graph in Graph 13-1 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.

15.2.6 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 J of this document).

15.3 SABIC Four-Factor Analysis of Potential SO₂ 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.

COGEN

The COGEN is a NG-fired combustion turbine that has inherently low SO₂ 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 SO₂ 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 SO₂ 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 SO₂ controls for COGEN is conducted.

COS Vent Oxidizer

SABIC evaluated a packed-bed wet scrubber as a potential technically feasible SO₂ 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, SO₂ 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 SO₂ 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 SO₂ is dependent upon the solubility of the pollutant in the NaOH scrubbing liquid.

Advantages of a scrubber for SO₂ 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 SO₂ control of the COS vent stream from the COS Vent Oxidizer.

Other Gas Absorber (Scrubber) Technologies for COS Vent Oxidizer SO₂ 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 SO₂ gas absorption technologies that are intended to control large volume (gas flow rate) and high SO₂ 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 SO₂ concentration due to the large amounts of coal combusted in the units.

The two broad categories of scrubber technologies used on large volume/high SO₂ 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 SO₂ 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 SO₂ concentration to make the scrubber technologies in this section technically feasible.

15.3.1 Cost of Compliance for Potential SO₂ 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 of the Indiana RH SIP Nitrogen Oxides and Sulfur Dioxide Four-Factor Analysis For Iron and Steel Mills, Aluminum Production and Plastics Manufacturing Plants and Electric Services Plant document and in Appendix J of this document with a detailed breakdown.

- As appropriate, SABIC used site-specific data and engineering judgment to refine the estimated costs summarized in Appendix A of the Indiana RH SIP Nitrogen Oxides and Sulfur Dioxide Four-Factor Analysis For Iron and Steel Mills, Aluminum Production and Plastics Manufacturing Plants and Electric Services Plant document and in Appendix J of this document, which contains additional details, references, and data sources for this SO₂ 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 SO₂ were used to estimate the annual costs necessary to operate a packed tower scrubber.

15.3.2 Time Necessary for Potential SO₂ Control Options Compliance

The technically feasible SO₂ 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 SO₂ 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 of the Indiana RH SIP Nitrogen Oxides and Sulfur Dioxide Four-Factor Analysis For Iron and Steel Mills, Aluminum Production and Plastics Manufacturing Plants and Electric Services Plant document and in Appendix J of this document 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.

15.3.3 Energy and Non-Air Impacts of Potential SO₂ Control Options

The cost of energy required to operate the SO₂ control options is presented in the detailed cost analysis presented in Appendix A of the Indiana RH SIP Nitrogen Oxides and Sulfur Dioxide Four-Factor Analysis For Iron and Steel Mills, Aluminum Production and Plastics Manufacturing Plants and Electric Services Plant document and in Appendix J of this document. 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.

15.3.4 Remaining Useful Life for SO₂ 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 15-3 SABIC Emission Units SO₂ 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	

15.3.5 SO₂ Emissions Trends at the SABIC Facility

SABIC facility-wide SO₂ emissions show a significant downward trend over the 11-year evaluation period, as reflected in Table 13-5 (on page 139) and Graph 13-2 (on page 140), as a result of the COGEN facility's commencement of operations in 2016. The line graph in Graph 13-2 shows the SO₂ emissions decreased substantially 2017

emissions after ceasing the use of coal as fuel to generate steam for process operations. SABIC facility wide SO₂ emissions decreased 89% from 2008 to 2018.

15.3.6 SABIC Reasonable Level of Control for SO₂ Emissions

The reasonable SO₂ 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 SO₂ 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 SO₂ emissions reduction (See Cost Effectiveness and Cost Estimate Spreadsheets in Appendix J of this document).

16.0 CLEAN AIR ACT REGULATION 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.

17.0 ALUMINUM PRODUCTION FACILITY

17.1 Warrick Newco LLC, formerly Alcoa Warrick Operations LLC (Alcoa) NO_x and SO₂ 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 SO₂ four-factor analysis in IDEM's RFI are listed below and the source of each unit's SO₂ 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 17-1 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

Potline Nos. 2, 3, 4, 5, and 6

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 SO₂ emissions are generated by the consumption of the carbon anode during the aluminum smelting process. The facility's hourly SO₂ 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.

Potline No. 2

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 PM₁₀ control and dry alumina scrubbers for total fluoride and SO₂ control. The system operates with a minimum of two reactor sections at any one time. SO₂ 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.

17.2 Alcoa Potential Four-Factor Analysis of Potential SO₂ Control Options

Alcoa chose a FGD system for Potlines 2-6 and the Anode Baking Ring Furnace and associated A-446 Dry Alumina Scrubbers. SO₂ 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 SO₂ emissions from the potlines, the FGD is evaluated for the potlines and the anode baking ring furnace.

17.2.1 Cost of Compliance for Potential SO₂ Control Options

In July 2007, Babcock Power Environmental (Babcock Power) provided Alcoa a budgetary proposal for a FGD system for the control of SO₂ emissions from Potlines 2 through 6. To estimate the capital cost of installing a FGD system to control SO₂ 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 SO₂ 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.

17.2.2 Time Necessary for Potential SO₂ 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.

17.2.3 Energy and Non-Air Impacts of Potential SO₂ 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.

17.2.4 Remaining Useful Life for SO₂ 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 17-2 Alcoa Emission Units SO₂ 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	

17.2.5 SO₂ Emissions Trends at the Alcoa Facility

Alcoa facility-wide SO₂ emissions show a significant downward trend over the 11-year evaluation period as reflected in Table 13-5 and Graph 13-2 on pages 139 and 140, respectively. The line graph in Graph 13-2 shows SO₂ emissions decreased substantially in 2016 (from 4,147 tons in 2015 which is the highest reported SO₂ 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 SO₂ emissions decreased 58% from 2008 to 2018.

17.2.6 Alcoa Reasonable Level of Control for SO₂ Emissions

The reasonable SO₂ 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 SO₂ cost-effectiveness values (\$ per ton of emissions reduction) for the addition of FGD for Potlines 2-6 is \$5,889 per ton of SO₂ emissions reduction and \$16,787 per ton of SO₂ emissions reduction for the Anode Baking Ring Furnace & A-446 Dry Alumina Scrubbers unit (See Cost Effectiveness and Cost Estimate Spreadsheets in Appendix A of the Indiana RH SIP Nitrogen Oxides and Sulfur Dioxide Four-Factor Analysis For Iron and Steel Mills, Aluminum Production and Plastics Manufacturing Plants and Electric Services Plant document and in Appendix J of this document).

In response to the FLM comments related to the Alcoa cost estimate, Warrick Newco LLC submitted additional information related to Alcoa's cost estimate and cost effectiveness analysis. See Appendix T for specific cost estimate and cost effectiveness details. According to updated information received from Warrick Newco, the revised cost effectiveness per ton of pollutant removed analysis resulted in a revised cost of \$1,579 per ton for a FGD retrofit for Potlines 2-6 and \$4,544 per ton for a FGD retrofit for the Anode Baking Ring Furnace & A-446 Dry Alumina Scrubbers unit.

18.0 CLEAN AIR ACT REGULATION 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 SO₂ 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 SO₂ emissions from the potline stacks and roof monitors and anode baking ring furnace at the A-446 Dry Alumina Scrubbers unit; although, SO₂ emission limitations for the Alcoa potlines were already established. The 2008 revised Ozone NAAQS has contributed to the reduction in SO₂ 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 SO₂ emissions from the affected facilities at the Alcoa plant, reducing ozone and toxic air emissions from these combustion sources will also contribute to SO₂ emission reductions.

19.0 ELECTRIC UTILITY SERVICES

19.1 Primary Energy - Cokenergy LLC (Cokenergy) NO_x and SO₂ 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 19-1. The unit's source of NO_x and SO₂ emissions and existing control measure(s) are described in this section.

Table 19-1 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 SO₂ and particulate emissions.

19.2 Cokenergy Four-Factor Analysis of Potential SO₂ Control Options

In 2014, Cokenergy contracted with an engineering firm to conduct a study to evaluate and optimize the existing FGD system that controls SO₂ 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 SO₂ 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, SO₂ 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 SO₂ 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 SO₂ 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 SO₂ emissions from the FGD system. These projects have reduced SO₂ emissions from the FGD by more than 15 percent. A summary of the actual SO₂ emissions and percent reduction of SO₂ prior to and after the extensive projects completed by Cokenergy are detailed in Table 19-2 on page 188.

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 SO₂ is summarized as well.

- HRSR Retubing
 - Completed retubing of all 16 of the HRSRs that allowed for a reduction in the amount of over scrubbing required by the FGD, reduced the pressure drop by using finned tubes, and reduced venting from the emergency bypass vent stacks.
- Reduce Flue Gas Volume
 - Replaced dampers and reduced air in-leakage rates to lower the high flue gas volumetric flow rate at the inlet of the SDA. The flue gas flow rates to the SDA were too high and resulted in a reduced capture efficiency of the SDA.
 - 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 SO₂ 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.
 - SO₂ 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 SO₂ absorption into the evaporating slurry droplets. The absorption of SO₂ into slurry droplets is the mechanism in which SO₂ is captured or removed from the flue gas. The captured SO₂ droplets exit the SDA as solids.
 - The increased residence time has a direct influence on higher SO₂ capture during spray droplet evaporation.

- Increase SO₂ 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 SO₂ removal as shown in Figure 3-2 in the Cokenergy four-factor analysis document submittal.
 - SO₂ 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 - Figure 3-3 in the Cokenergy four-factor analysis document submittal.
 - 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 SO₂ removal efficiency of 80.3% to achieve the current Title V permit limit of 1,656 lb/hr.
- Two SDAs Operating in Parallel Scenario - Figure 3-4 in the Cokenergy four-factor analysis document submittal.
 - 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 SO₂ removal rates.
- DSI with Trona with One or Two SDAs in Operation Scenarios - Figure 3-5 in the Cokenergy four-factor analysis document submittal.
 - The option of adding a DSI upstream of both the single SDA and dual SDA configurations was considered. The SO₂ 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 SO₂ 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 SO₂ emissions from the IHCC emergency bypass vent stacks with the emissions from Cokenergy using the emission tracking system (ETS) in coordination with the Cokenergy CEMS. ETS uses coke production data, HRSG steam production, vent lid status, and coal analytical data to calculate the potential SO₂ emissions from venting using a material balance. Cokenergy provides the actual SO₂ data from the stack CEMS.

Table 19-2 on page 188 provides a summary of this ETS output with additional calculations to demonstrate the impact of the FGD enhancements made in recent years on improved SO₂ 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 SO₂ emissions, bypass SO₂ emissions, total SO₂ emissions, coal charge, coal sulfur content, coke production, and sulfur content of the finished coke were used to estimate SO₂ input and output to and from the FGD system which estimates the FGD SO₂ control efficiency.

19.2.1 Cost of Compliance for Potential SO₂ 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 SO₂ 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 SO₂. 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 19-2 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 SO₂ control efficiencies is shown on the next page.

Table 19-2 Cokenergy Flue Gas Desulfurization SDA SO₂ 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.

SDA Control Efficiency Calculations

$$\text{Raw } SO_2 \text{ Input to FGD} = [\text{Coal Charge (tons)} \times \text{Coal Sulfur Content (\%)}] - \frac{64 \text{ lbs } SO_2}{\text{Ton}} \times \frac{2000 \text{ lbs}}{32 \frac{\text{lbs } S}{\text{lbmol}}} \times \frac{1 \text{ day}}{24 \text{ hours}}$$

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

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

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.

19.2.2 Cokenergy Reasonable Level of Control for SO₂ 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 SO₂ 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.

20.0 CLEAN AIR ACT REGULATION CONTROLLING ELECTRIC SERVICES FACILITIES

While there are no federal regulations that specifically target SO₂ emissions from electric services operations, the revised 2008 Ozone and 2010 one-hour primary SO₂ NAAQS updates have contributed to reductions in SO₂ 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. SO₂ 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 January 25, 2018 between Indiana, U.S. EPA and Indiana Harbor Coke Company, SunCoke and Cokenergy established additional operating limitations and monitoring requirements related to SO₂ that were incorporated into the source's Title V Operating permit and currently remain in place. The Cokenergy have been incorporated into the Lake County Sulfur Dioxide Emission Limitations and is referenced in 326 IAC 7-4.1-7 and 7-4.1-8 (Indiana Harbor Coke Company sulfur dioxide emission limitations).

21.0 ON-THE-BOOKS CONTROLS IMPLEMENTED DURING THE RH SIP FIRST PLANNING PERIOD (2008-2018)

The following federal "on-the-books" control measures have been implemented since the submittal of Indiana's RH SIP for the first implementation period submitted in March 2011 and remain in place to continue realizing emission reductions from the control strategies.

21.1 Tier 2 Vehicle Emissions and Gasoline Standards Rule

On February 10, 2000, the U.S. EPA published the final rule for the Tier 2 Program, which set federal emission standards for passenger vehicles, including sport utility vehicles, minivans, vans, and pick-up trucks, as well as passenger cars. The program created fleet-averaging emission standards for NO_x, allowing manufacturers to produce vehicles with varying emissions, as long as the fleet of vehicles produced by a manufacturer had average NO_x emissions at or below the federal standards. The Tier 2 Vehicle Emissions and Gasoline Standards Rule reduced new vehicle NO_x emissions to an average of 0.07 grams per mile and was phased in from 2004 to 2009, beginning with the 2005 model year. The program continues to provide emission reductions from mobile sources as older sources in the fleet continue to be replaced with new sources.

Beginning in 2006, EPA began to phase-in more stringent regulations to lower the amount of sulfur in diesel fuel to 15 ppm. This fuel is known as ultra-low sulfur diesel (ULSD).

EPA's diesel standards target emissions from two different sources:

- On-road (or highway) vehicles; and
- Non-road engines and equipment.

Collectively, diesel standards reduce harmful emissions from both on-road and non-road diesel sources by more than 90% since the EPA began regulating diesel fuel sulfur levels.

21.2 Tier 3 Vehicle Emission and Fuel Standards Program

On April 28, 2014, the U.S. EPA published the final rule for the Tier 3 Vehicle Emission and Fuel Standards Program. The Tier 3 program is part of a comprehensive approach to reducing the impacts of motor vehicles on air quality. The program considers the vehicle and its fuel as an integrated system, setting more stringent vehicle emissions standards and lowering the sulfur content of gasoline beginning in 2017. The vehicle emission standards will reduce tailpipe and evaporative emissions from passenger cars, light-duty trucks, medium-duty passenger vehicles, and some heavy-duty vehicles. The fuel standards will enable more stringent vehicle emission standards and make emission control systems more effective.

21.3 Heavy-Duty Diesel Engine and Highway Diesel Fuel Rule

The U.S. EPA finalized the Heavy-Duty Diesel Engine and Highway Diesel Fuel Rule, a program to reduce emissions from heavy-duty trucks and buses by more than 90%, on January 18, 2001. The program set emission standards for PM, NO_x, and non-methane hydrocarbons, for new heavy-duty diesel engines and required a 97% reduction in the sulfur content of highway diesel fuel to enable the use of more modern pollution-control technology on heavy-duty vehicles. The Heavy-Duty Diesel Engine and Highway Diesel Fuel Rule was phased in between 2007 and 2010.

After 2010, EPA's diesel standards required that:

- All highway diesel fuel supplied to the market be ULSD; and
- All highway diesel vehicles must use ULSD.

21.4 Non-road Engine and Diesel Fuel Rule (Tier 4)

On June 29, 2004, the U.S. EPA published the final Non-road Diesel Engine and Diesel Fuel Rule for diesel engines used in most construction, agricultural, industrial, and airport equipment. The program established NO_x and PM emission standards for non-road diesel engines and mandated the reduction of sulfur levels in diesel fuel for non-road diesel

engines by more than 99%. Implementation of the Non-road Diesel Engine and Diesel Fuel Rule began in 2008 and was fully phased in by 2014.

From 2007 to 2014, low sulfur diesel fuel (specified at 500 ppm) and ULSD fuel was phased in for nonroad, locomotive, and marine (NRLM) diesel fuel.

After 2014, EPA's diesel standards require that:

- All nonroad, locomotive, and marine (NRLM) diesel fuel must be ULSD; and
- All NRLM engines and equipment must use this fuel (with some exceptions for older locomotive and marine engines).

21.5 2010 SO₂ NAAQS

On June 2, 2010, the U.S. EPA promulgated a new primary NAAQS for SO₂, replacing the two primary standards of 140 parts per billion (ppb) evaluated over 24-hours and 30 ppb evaluated over an entire year with the 1-hour standard of 75 ppb. The primary SO₂ NAAQS is met when the 3-year average of the annual 99th percentile of the daily maximum 1-hour average concentration at any ambient air quality monitor in an area does not exceed 75 ppb.

The U.S. EPA published a notice announcing designated nonattainment areas under the 1-hour SO₂ standard on August 5, 2013. Designations were made based on monitored air quality data measured during 2009, 2010, and 2011. Parts of Daviess, Marion, Morgan, Pike, and Vigo counties in Indiana were designated nonattainment under subpart 1 of Section 107 of the CAA. Emission limitations for individual units were adopted and made permanent and enforceable in Indiana's revised Sulfur Dioxide Rules, 326 IAC 7, on September 30, 2015. The compliance deadline was January 1, 2017.

Implementation of the revised SO₂ NAAQS was delayed for areas not monitoring violations of the standard while the U.S. EPA reconsidered its approach to the designation process. Following the initial August 2013 designations (Round 1 Designations), three lawsuits were filed against the U.S. EPA in different U.S. Court Districts, alleging that the agency had failed to perform a nondiscretionary duty under the CAA by not designating all portions of the country by the June 2013 deadline.

In an effort intended to resolve the litigation in one of those cases, the plaintiffs (Sierra Club and the Natural Resources Defense Council) and the U.S. EPA filed with the U.S. District Court of the Northern District of California a proposed consent decree that specified a schedule for the U.S. EPA to complete the remaining designations for the rest of the country in three additional rounds. On March 2, 2015, the Court entered the consent decree and issued an enforceable order for the U.S. EPA to complete the area designations according to the consent decree schedule.

Pursuant to the consent decree order, the U.S. EPA must complete the remaining designations on a schedule that contains three specific deadlines. By no later than July 2,

2016, the U.S. EPA must designate two groups of areas: (1) areas that have newly monitored violations of the 2010 SO₂ standard and (2) areas that contain any stationary source that according to the U.S. EPA's Air Markets Database either emitted more than 16,000 tons of SO₂ in 2012 or emitted more than 2,600 tons of SO₂ and had an annual average emission rate of at least 0.45 of SO₂/MMBtu in 2012 and has not announced retirement as of March 2, 2015 (Round 2 Designations).

There are five EGUs in Indiana that meet the criteria established in the court order for the July 2016 deadline. IDEM worked with these sources to provide the U.S. EPA the most recent information available for making designation and boundary decisions. The last two deadlines for completing remaining designations are December 31, 2017 (Round 3 Designations) and December 31, 2020 (Round 4 Designations). The designations completed by these later deadlines are expected to be informed by information provided by the states pursuant to the U.S. EPA's Data Requirements Rule (DRR).

On August 10, 2015, the U.S. EPA finalized the DRR which sets forth the requirements for each state air agency to monitor or model ambient SO₂ levels in areas with large sources of SO₂ emissions to help implement the 1-hour primary SO₂ NAAQS. This final rule establishes that, at a minimum, each state air agency must characterize air quality around sources that emit 2,000 tons per year or more of SO₂.

By January 15, 2016, the DRR required each air agency to submit a list to U.S. EPA that identified all sources within its jurisdiction around which SO₂ air quality must be characterized. On January 7, 2016, based on annual SO₂ emissions data for the year 2014, IDEM identified eleven facilities in Indiana as being subject to air quality characterization under Round 3 Designations. By July 1, 2016, each air agency was required to notify U.S. EPA, for each source area identified on its list, the approach (ambient monitoring or air quality modeling) it would use to characterize air quality. In lieu of characterizing areas around listed sources, air agencies may indicate by July 1, 2016, that they would adopt permanent and enforceable emission limitations that would limit those source(s) emissions below the DRR 2,000 tons per year threshold.

The EPA issued a decision to retain the existing primary NAAQS for SO₂ on February 25, 2019 based on a review of the full body of scientific evidence and exposure/risk information available. The EPA's review determined that the existing NAAQS protects the public health with an adequate margin of safety.

21.6 Mercury and Air Toxics Standard Rule

On December 16, 2012, the U.S. EPA published a rule to reduce emissions of toxic air pollutants from power plants. The National Emission Standards for Hazardous Air Pollutants (NESHAP) from Coal- and Oil-Fired Electric Utility Steam Generating Units, also referred to as the Mercury and Air Toxics Standards rule for power plants, targets toxic air pollutants from new and existing electric utility steam generating units larger

than 25 MW that burn coal or oil for the purpose of generating electricity for sale and distribution through the national electric grid to the public.

The MATS rule establishes numeric emission limits for mercury, PM, and HCl emissions from coal fired EGUs, and PM, HCl, and hydrofluoric acid emissions from oil-fired EGUs. This includes numeric emission limits for SO₂ (as an alternative to HCl), individual non-mercury metal air toxics and total non-mercury metal air toxics (as alternatives to PM), and work practice standards, instead of numeric limits, to limit organic air toxics. Though the standards target toxic air pollutants, the controls needed for compliance also provide significant SO₂ emission reductions.

The New Source Performance Standards for fossil-fuel-fired EGUs, also signed under the MATS rule, revises the standards new coal- and oil-fired power plants must meet for PM, SO₂, and NO_x. Existing sources had up to 4 years to comply with MATS, if needed. The compliance deadline was March 15, 2016, which include 3 years provided to new and existing sources by the CAA and an additional year state permitting authorities could grant under the CAA to existing sources as needed for technology installation.

22.0 CLASS I AREAS MODELED BY LADCO

The CAA sets as a national goal, “the prevention of any future, and the remedying of any existing, impairment of visibility in Class I areas which impairment results from manmade air pollution” for RH. In the six-state LADCO region, there are four Class I areas: Isle Royale National Park and Seney National Wildlife Refuge in northern Michigan and Voyageurs National Park and Boundary Waters Canoe Area National Wilderness Area in northern Minnesota. The EPA visibility rules (64 FR 35714, July 1, 1999) require reasonable progress toward achieving “natural conditions” by the year 2064. Table 22-1 lists the areas that were modeled in LADCO’s RH modeling (completed in June of 2021) in which Indiana was estimated to have visibility impacts.

Table 22-1 Class I Areas Modeled by LADCO

Class I Area	Identifier	State
Acadia National Park	ACAD1	Maine
Boundary Waters Canoe Area National Wilderness Area	BOWA1	Minnesota
Brigantine National Wilderness Area	BRIG1	New Jersey
Caney Creek National Wilderness Area	CACR1	Arkansas
Cape Romain Wilderness Area	ROMA1	South Carolina
Cohutta Wilderness Area	COHU1	Georgia
Dolly Sods National Wilderness Area	DOSO1	West Virginia
Great Smoky Mountain/Joyce Kilmer Slickrock Wilderness Areas	GRSM1	Tennessee
Hercules-Glades National Wilderness Area	HEGL1	Missouri
Isle Royale National Park	ISLE1	Michigan
James River Face National Wilderness Area	JARI1	Virginia
Lye Brook National Wilderness Area	LYBR1	Vermont
Mammoth Cave National Park	MACA1	Kentucky
Mingo National Wilderness Area	MING1	Missouri
Okefenokee/Wolf Island Wilderness Areas	OKEF1	Georgia
Saint Mark’s Wilderness Area	SAMA1	Florida
Seney National Wilderness Area	SENE1	Michigan
Shenandoah National Park	SHEN1	Virginia
Sipsey Wilderness Area	SIPS1	Alabama
Swanquarter Wilderness Area	SWAN1	North Carolina
Upper Buffalo National Wilderness Area	UPBU1	Arkansas
Voyageurs National Park	VOYA2	Minnesota

The haze results show that all Class I areas in the eastern U.S. of which Indiana could impact are expected to be below the uniform rate of visibility improvement values for 2028. This means the progress of emission reductions throughout Indiana and the country over the past two decades are providing visibility improvement at all Class I areas in the eastern U.S potentially impacted by Indiana. As for the second implementation period for the RH Rule, visibility is better than expected at this point in time and additional emission reductions anticipated in the future will continue to realize even further visibility improvements.

23.0 REGIONAL HAZE MODELING RESULTS FOR INDIANA

Based on LADCO's source apportionment modeling results for 2028, Indiana selected those Class I areas where visibility was impacted by emissions from Indiana sources. The Class I areas which had a visibility impact of 1.5% or greater by emissions from Indiana sources were selected as areas that were significantly impacted, based on base year 2016 emissions.

23.1 Class I Area Selection

A variety of technical, quantitative approaches exist to assess which out-of-state Class I areas may be affected by aggregate emissions from a given state. The most common approach in the first implementation period was to use a photochemical transport model to track the contribution due to emissions from whole states to specific Class I areas. This approach has been used for the second implementation period as well and has also included source apportionment modeling to look at visibility impacts from emission sector groups and individual sources. In addition, Indiana has used back trajectory analyses as weight of evidence information to show whether air from Indiana impacted Class I areas on the 20% most impaired days.

Indiana has opted to determine its visibility impacts based on photochemical modeling provided by LADCO. LADCO provided RH modeling based on the 2016 emission platform. This modeling predicted the 2028 visibility levels, in both inverse megameters and deciviews, at Class I areas throughout the United States on the 20% most anthropogenically impaired days. From the 2016 emission platform modeling, Indiana selected those Class I areas where visibility was impacted by emissions from Indiana sources, based on the contribution threshold level. Those Class I areas which had a visibility impact contribution of 1.5% or greater from Indiana emissions were selected as areas that were significantly impacted. Indiana chose the 1.5% visibility impact contribution threshold as a conservative value to determine the reasonable contributions of Indiana's sources on visibility impairment. This threshold proves to be an excellent threshold as it maintains adequate geographic coverage of potential visibility impacts from Indiana on surrounding Class I areas. This geographic coverage ensures that Class I areas closer to Indiana that are captured in the modeling will be representative of Class I areas further from the state. If Indiana's total light extinction (measured in inverse megameters) modeled 1.5% or more of the total light extinction at the Class I area on the 20% most anthropogenically impaired days, then the Class I area was determined to be significantly impacted by Indiana emissions. This resulted in 17 Class I areas being impacted significantly by Indiana emissions. An additional 3 areas were added: Boundary Waters Canoe Area and Voyageurs National Park in Minnesota as part of the LADCO region, and Caney Creek in Arkansas based on an ASK from that state. Table 23-1 lists the Class I areas that were selected by Indiana, the state those areas are located, the 2016-2028 light extinction value, Indiana's contribution to the light extinction, and Indiana's percentage of light extinction to demonstrate the potential modeled visibility impairment. Results were taken from the LADCO RH modeling TSD.

Table 23-1 Modeled Visibility Impacts on Surrounding Class I Areas - Indiana

Class I Area	State	2016-2028 Total Light Extinction (Mm⁻¹)	Indiana Contribution to 2016-2028 Total Light Extinction (Mm⁻¹)	Indiana Impact of 2016-2028 Total Light Extinction Percentage
Mammoth Cave	Kentucky	74.2	8.3	11.2 %
Sipsey	Alabama	61.0	3.6	5.90 %
Dolly Sods/ Otter Creek	West Virginia	54.0	3.0	5.56 %
Great Smoky Mountains/Joyce-Kilmer- Slickrock	Tennessee	51.0	2.7	5.29 %
Shenandoah	Virginia	50.6	2.6	5.14 %
Cohutta	Georgia	51.8	2.5	4.83 %
Mingo	Missouri	69.7	2.9	4.16 %
Seney	Michigan	57.4	2.3	4.01 %
James River	Virginia	53.4	2.0	3.75 %
Linville Gorge	North Carolina	45.7	1.3	2.84 %
Lye Brook	Vermont	42.9	1.0	2.33 %
Brigantine	New Jersey	69.4	1.6	2.30 %
Shining Rock	North Carolina	41.4	0.9	2.17 %
Upper Buffalo	Arkansas	54.4	1.1	2.02 %
Hercules-Glades	Missouri	59.4	1.2	2.02 %
Swanquarter	North Carolina	48.5	0.9	1.85 %
Isle Royale	Michigan	48.6	0.9	1.85 %
Caney Creek	Arkansas	54.4	0.6	1.10 %
Boundary Waters	Minnesota	40.5	0.3	0.74 %
Voyageurs	Minnesota	41.0	0.2	0.49 %

Figure 23-1 shows the locations of the 20 Class I areas with visibility impacts from Indiana emissions of 1.5% or greater, as determined by the 2016 - 2028 LADCO modeling for RH.

Figure 23-1 Map of Class I Areas Determined to be Impacted by Indiana Emissions (1.5%)



Results of a monitored and modeled comparison are found in Table 23-2. Class I areas located at a further distance will receive visibility benefits from emissions reductions even though Indiana's contribution on visibility impairment would have been calculated to be much less. These results were provided by LADCO regional haze modeling results for both 2011 and 2016. All monitored and modeled values were taken from LADCO spreadsheets for each modeling evaluation and can be provided through LADCO.

Table 23-2 Monitoring and Modeled Visibility Results for Class I Areas (20% Most Impaired Days)

Site	2000-2004 Monitored Baseline (dv)	2009-2013 Monitored Baseline (dv)	2014-2018 Monitored Baseline (dv)	2011 base - 2028 Modeled Results (dv)	2016 base - 2028 Modeled Results (dv)
Boundary Waters	18.4	16.4	14.0	14.4	13.2
Voyageurs	17.9	17.1	14.2	15.1	13.4
Seney	23.6	19.9	17.6	17.3	16.7
Isle Royale	19.6	17.6	15.5	15.5	14.8
Hercules-Glades	25.2	21.6	18.8	19.7	17.5
Mingo	26.3	22.5	20.1	20.4	18.9
Caney Creek	24.0	21.1	18.3	19.5	16.7
Upper Buffalo	24.2	20.5	18.0	18.8	16.7
Mammoth Cave	29.8	24.0	21.0	20.2	19.7
Cohutta	29.1	21.1	17.4	15.8	16.2
Dolly Sods	28.3	21.6	17.7	16.7	16.5
Shenandoah	28.3	20.7	17.1	15.9	15.8
James River Face	28.1	21.3	17.9	16.9	16.5
Linville Gorge	28.1	20.4	16.4	15.3	15.0
Shining Rock	28.1	N/M	15.5	N/M	13.9
Swanquarter	23.8	19.7	16.3	16.1	15.6
Brigantine	27.4	22.3	19.3	19.0	18.6
Lye Brook	23.6	18.1	14.7	15.0	14.1
Great Smoky Mountains	29.1	21.4	17.2	16.1	16.0
Sipsey	27.7	21.8	19.0	17.9	17.8

Note: Shining Rock had incomplete data for 2011 and therefore no results were determined in the 2011-2028 LADCO Modeling.

Results for Class I areas analyzed show 2014-2018 baseline monitored values, as determined through the IMPROVE monitoring data, are lower than the modeled visibility impacts at each Class I area for 2028, based on the 2011 emissions and nearly match the modeled results from the base-year 2016 - future year 2028 modeling. The significance of the 2014-2018 monitored period is it marks the end of the first implementation period of the RH Rule and shows the progress at all Class I areas of improved visibility.

While this fact does not absolve states from addressing key elements of the RH Rule, it does emphasize the emissions reductions that have occurred throughout the country have

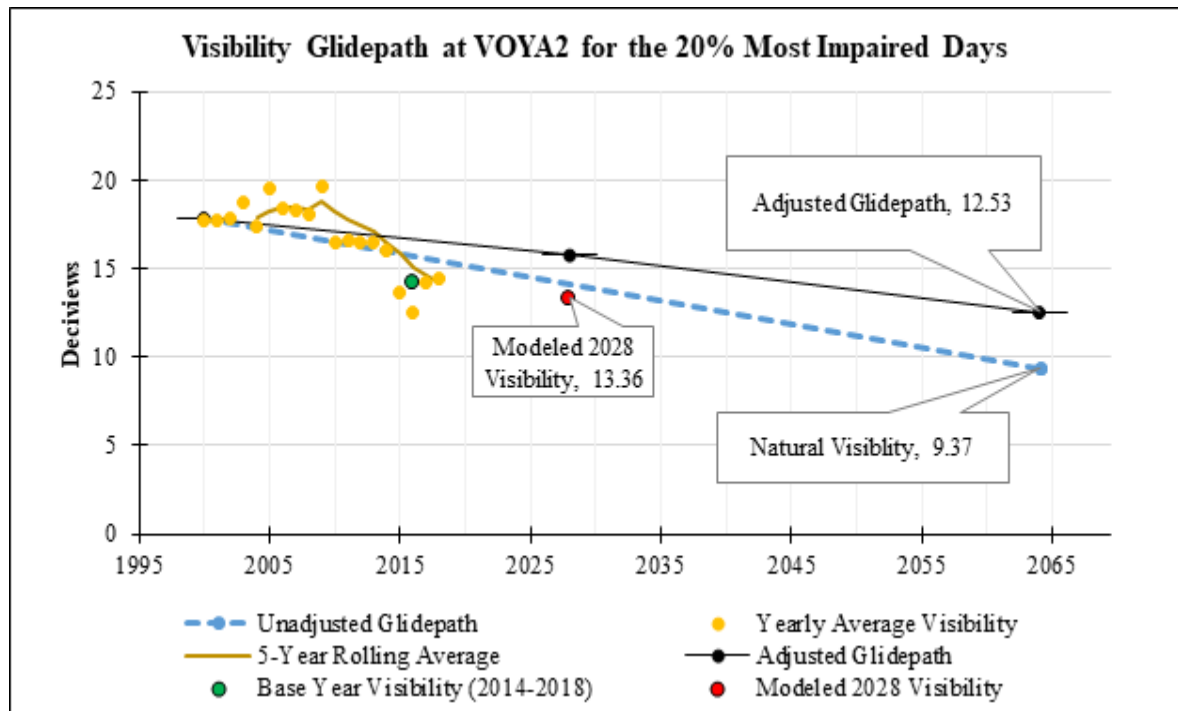
realized monitored visibility benefits and are well ahead of future projections of visibility impacts at the Class I areas for 2028. The steady decline of visibility impacts at the Class I areas from anthropogenic emissions are significant and indicate that states are taking the necessary steps to remain ahead of the schedule in the glidepaths and are projected to approach natural visibility conditions ahead of 2064.

23.2 Voyageurs National Park & Boundary Waters Canoe Area National Wilderness Area - Minnesota

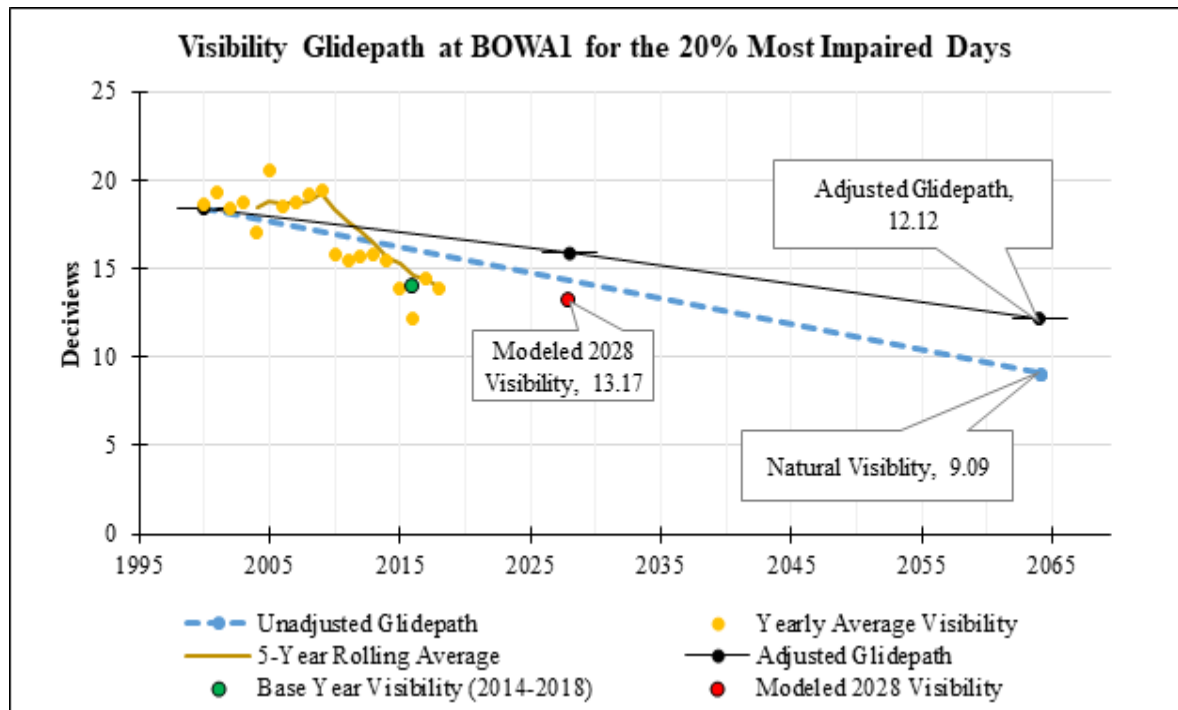
Minnesota's RPGs for the RH SIP first implementation plan relied on a projected 34% reduction of SO₂ emissions statewide from the 2002 base case by 2008. Minnesota achieved (and exceeded) this statewide reduction goal with a 61% reduction in statewide SO₂ emissions, and continued implementation of the state's Long Term Strategy controls provides further reductions according to "Minnesota's Five-Year Regional Haze Progress Report State Implementation Plan," dated December 2015. Statewide NO_x emissions in Minnesota also decreased from the 2002 base case and exceeded modeled reduction targets for point sources and by 2011, Minnesota had achieved a 38% reduction in statewide NO_x emissions - nearly achieving the 41% reduction relied upon for the state's 2018 RPGs.

While Indiana sources have shown an impact on these Class I areas through modeling studies conducted for the RH SIP second implementation period, Minnesota has determined that several other states are significant contributors to visibility impairment in these areas at this time and is working with them as they develop their RPGs for the second implementation period. Results for all Class I areas analyzed show 2014-2018 baseline monitored values, as determined through the IMPROVE monitoring data, nearly match the modeled results from the base-year 2016 - future year 2028 modeling, indicating the Class I areas are well ahead of its uniform rate of progress goals. Graphs 23-1 and 23-2 show the URP Glidepath for Voyageurs and Boundary Waters Class I areas. The glidepath data for the graphs can be found in the LADCO RH modeling TSD and modeling files.

Graph 23-1 Voyageurs National Park URP Glidepath - 2016 Base-Year



Graph 23-2 Boundary Waters National Wilderness Area URP Glidepath - 2016 Base-Year



Although Indiana has participated in the consultation calls and the LADCO modeling process used by Minnesota to reach their conclusions, Minnesota has developed a long-term strategy sufficient to meet their 2028 RPGs and has not requested additional

assistance from Indiana. Indiana concurs that this is the best approach for addressing visibility impairment at Voyageurs and Boundary Waters Class I areas at this time. Therefore, no further analysis for this SIP is necessary. Indiana will continue to work with Minnesota and LADCO to evaluate the progress in these Class I areas.

23.3 Isle Royale National Park and Seney National Wilderness Area - Michigan

Michigan determined that existing and on-the-books controls (those controls scheduled in response to regulatory actions within the first implementation period timeframe), combined with reductions necessary to meet the new 24-hour fine particulates standard and the new ozone standard would be sufficient to meet their RPGs. Three Indiana facilities, Rockport in Spencer County, Gallagher in Floyd County, and Clifty Creek in Jefferson County were included on Michigan's list of the top 30 facilities impacting visibility at Isle Royale and Seney, inside and outside the state, according to the state's RH SIP for the first implementation period. As a result, there were controls planned for all three of these facilities.

Under the terms of the Fifth Modification of the AEP System Eastern Fleet NSR Consent Decree signed on July 17, 2019, the Rockport Plant must install and operate Enhanced Dry Sorbent Injection Systems by June 1, 2020 on Unit 2 and by December 31, 2020 on Unit 1. SO₂ was further limited to 10,000 tons per year from both units combined starting in 2021 through 2028 and reduced to 5,000 tons per year beginning in 2029, concurrent with the required retirement of Unit 1 by December 31, 2028. The modification requires compliance with a 0.15 lb/MMBtu 30 day rolling average SO₂ emission rate on the combined stack beginning with the 30th SO₂ operating day on the combined stack after January 1, 2021. The modification further required the installation and operation of SCR on Unit 2 by June 1, 2020 (SCR was installed on Unit 1 in 2017). In addition, the modification requires compliance with a 0.09 lb/MMBtu 30 day rolling average NO_x emission rate on the combined stack beginning with the 30th NO_x operating day on the combined stack after January 1, 2021. Gallagher, which had four units, signed a consent decree in December 2009 to reduce SO₂ and NO_x emissions by January 1, 2013. Two of the four units (Units 2 and 4) were retired in 2012 and DSI systems were installed on the other two units in 2011. Clifty Creek began construction of FGDs for all five units, but postponed completion when CAIR was vacated, citing economic concerns; however, the installations of all five FGDs were completed 2013 prior to CSAPR being upheld in 2014.

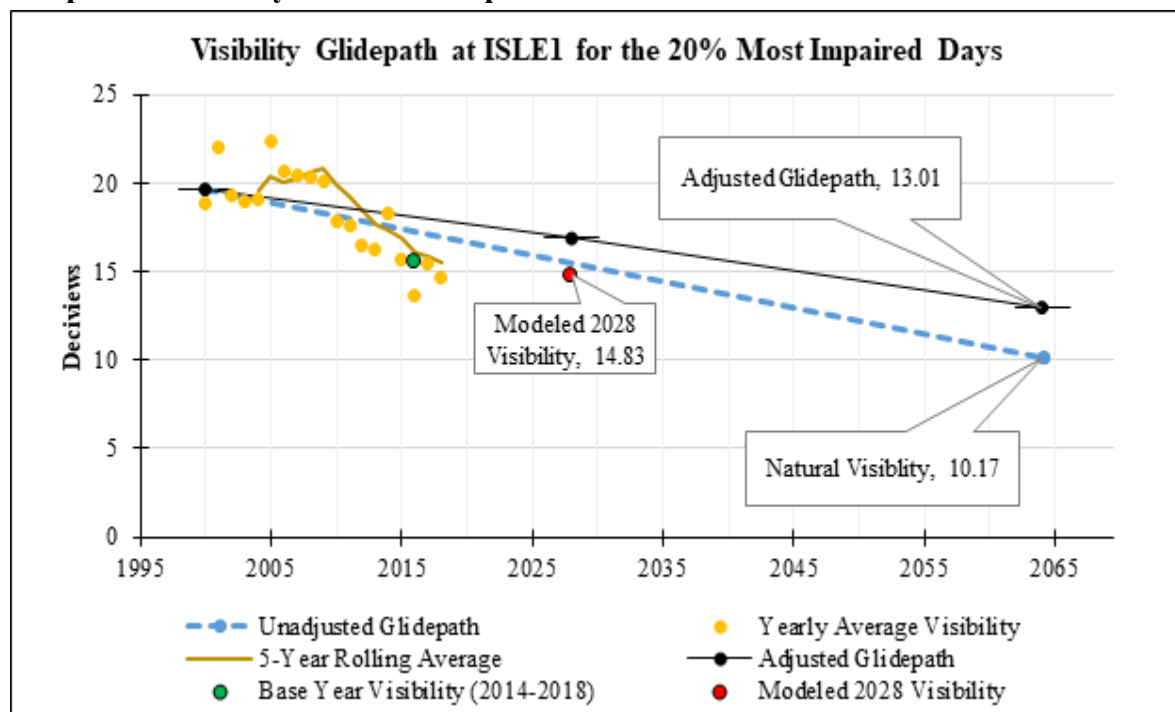
In January 2011, NIPSCO also signed a consent decree. NIPSCO operates four large EGUs in northern Indiana, Bailly in Porter County, Mitchell in Lake County, Michigan City in LaPorte County, and Schahfer in Jasper County. While these facilities were not listed as among the largest sources impacting Seney and Isle Royale, because of their size and proximity, controls to be installed were expected to result in less visibility impairment. Specifically, Mitchell was to be permanently shut down, two new FGDs at Schahfer and one at Michigan City were to be added, and upgrades were to be made to two FGDs at Schahfer along with two upgrades to FGDs at Bailly, although all three units at Bailly were ultimately shut down by the end of 2018. Also, some NO_x controls were to

be added and upgraded, along with a system wide cap on overall emissions. These controls were phased in through the end of 2015 as anticipated.

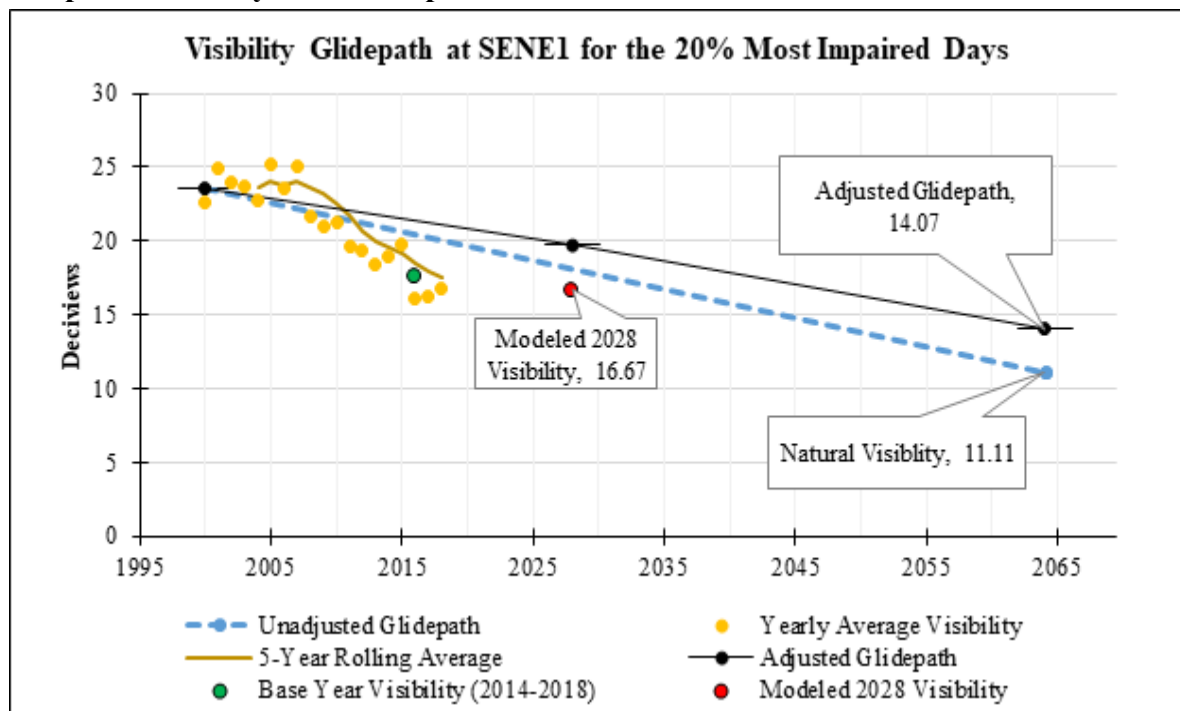
According to Michigan's "Five-Year Regional Haze Report State Implementation Plan," dated October 19, 2015, the 2011 totals for NO_x and SO₂ shows downward trends compared to the 2005 data for almost all categories. Total NO_x emissions were reduced by 21% and SO₂ emissions by 38% over the 2005 to 2011 period. Michigan concluded that the state's current Regional Haze SIP was adequate and required no further revision at that time to achieve 2018 visibility goals.

Indiana sources have shown a visibility impact on these Class I areas through modeling studies. As such, Indiana and the other Midwestern states participated extensively in the LADCO modeling and data analysis efforts for fine particulates, ozone, and haze in these areas. Results for all Class I areas analyzed show 2014-2018 baseline monitored values, as determined through the IMPROVE monitoring data, nearly match the modeled results from the base-year 2016 - future year 2028 modeling. Graphs 23-3 and 23-4 clearly show the reasonable rate of progress for visibility for the two Michigan Class I areas are well ahead of their respective uniform rate of progress goals according to the modeling results. The glidepath data for the graphs can be found in the LADCO RH modeling TSD and modeling files.

Graph 23-3 Isle Royale URP Glidepath - 2016 Base-Year



Graph 23-4 Seney URP Glidepath - 2016 Base-Year



Michigan has realized visibility benefits based on IMPROVE monitoring and LADCO modeling results. Based on these results, Michigan believes existing and future controls will suffice in addressing visibility at its Class I areas. Indiana concurs that this is the best approach for addressing visibility impairment at Isle Royale National Park and Seney National Wilderness Area Class I areas at this time. Therefore, no further analysis for this SIP is necessary at this time; however, Indiana will continue to work with Michigan and LADCO to evaluate the progress in these Class I areas.

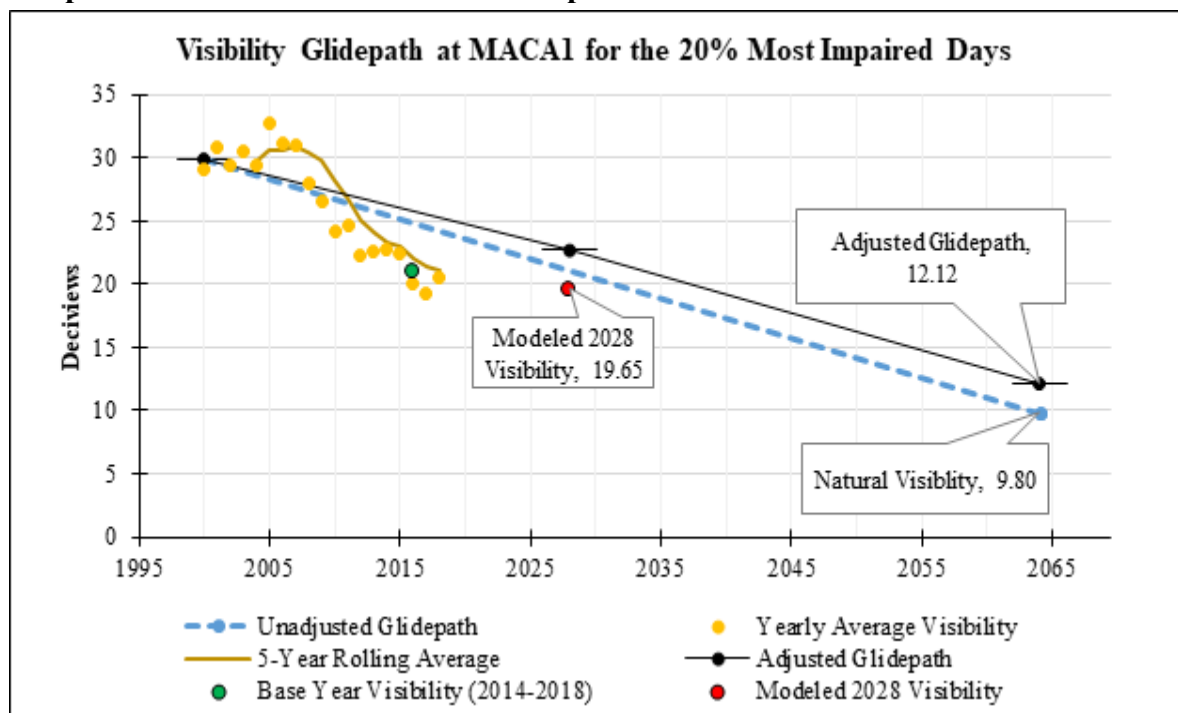
23.4 Mammoth Cave National Park - Kentucky

At the time Kentucky's Regional Haze SIP for the first implementation period was developed, EGU sources in Kentucky and Indiana were required to comply with the requirements of the final CSAPR/CAIR. Kentucky determined that these controls were sufficient to address visibility in this Class I area. Further, VISTAS modeling showed that Mammoth Cave was more than meeting its uniform rate of progress, therefore, Kentucky determined that no additional reductions were needed from Indiana. However, there was an Indiana source, Alcoa, subject of the Indiana BART rule that was determined to significantly impact this area. Visibility impacts from Alcoa were anticipated to be reduced further as a result of the announcement that their smelter would be permanently shut down by April of 2016. The Alcoa smelter shutdown temporarily but restarted and continues to operate at this time.

In addition, six EGUs from Indiana were identified as possibly impacting Kentucky's Class I area, with a 1% or more contribution to the Mammoth Cave area of influence according to the "Kentucky State Implementation Plan (SIP) Revision: Regional Haze 5-Year Periodic Report 2008-2013 For Kentucky's Class I Federal Area," dated September 17, 2014. Two of the six units are located at the Rockport Power Generating Station. The other four are located at the Gallagher Power Generating Station. The DSI's proposed for compliance with CSAPR, and MATS were accounted for in Kentucky's Regional Haze SIP for the first implementation period and installed on four of the six EGUs, two at each facility. The other two units located at Gallagher were shut down, which was also accounted for in Kentucky's Regional Haze SIP for the first implementation period. SCR systems were installed in addition to the new DSI units on the two EGUs at Rockport. Therefore, potential SO₂ emissions from the six EGUs in Indiana identified as possibly impacting visibility at Mammoth Cave have been reduced as anticipated and potential NO_x emissions will be reduced further than anticipated for these sources in Kentucky's RH SIP.

SESARM modeling has shown that Mammoth Cave is more than meeting its uniform rate of progress (glidepath) and has determined that current controls are sufficient to address visibility in this area and no additional reductions are needed from Indiana at this time. Analyses performed by LADCO show similar results.

Graph 23-5 Mammoth Cave URP Glidepath - 2016 Base-Year



Results for all Class I areas analyzed show 2014-2018 baseline monitored values, as determined through the IMPROVE monitoring data, nearly match the modeled results from the base-year 2016 - future year 2028 modeling, indicating the Class I area is well ahead of its uniform rate of progress goals. Indiana concurs that this is the best approach for addressing visibility impairment at Mammoth Cave at this time as substantial emission reductions have occurred over the past decade and additional emission reductions are anticipated throughout the second implementation period for the RH Rule. Therefore, no further analysis for this SIP is necessary.

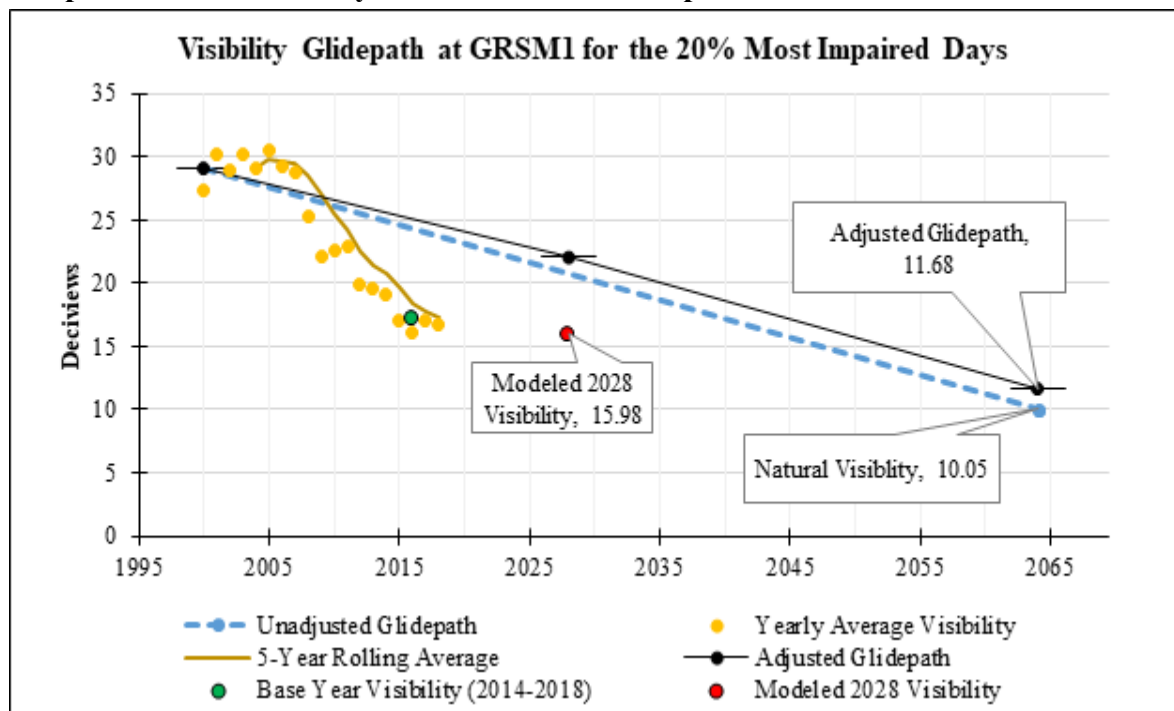
23.5 Great Smoky Mountains National Park - Tennessee

VISTAS modeling conducted to assist in developing RPGs showed that the long-term strategy developed for this Class I area easily met the glidepath through 2018. In the "Technical Analyses Supporting Regional Haze State Implementation Plan," June 8, 2007, North Carolina Department of Environment and Natural Resources stated that contributions from other RPOs are comparatively small and the greatest benefits would likely be from further EGU reductions within the VISTAS states.

The "Regional Haze 5-Year Periodic Review State Implementation Plan for North Carolina Class I areas," dated May 31, 2013, provides a new projection for 2018 emissions from the EGUs subject to North Carolina's Clean Smokestacks Act (CSA). The CSA is North Carolina's primary control strategy in the state's Regional Haze SIP. SO₂ and NO_x emissions from coal-fired EGUs subject to this act are well below the act's system caps and well below what was modeled in North Carolina's Regional Haze SIP. In fact, statewide SO₂ emissions from coal-fired EGUs decreased by 80% over the 5-year period (2002 to 2011) and statewide NO_x emissions dropped by 32%. Since the EGU sector represents over 50% of statewide SO₂ emissions from stationary sources, this is a clear sign that the Class I areas in North Carolina are on track to meet or exceed their 2018 RPGs and future SO₂ emissions are expected to decline further as a result of federal control measures focused on EGU and other large industrial sources that have yet to be implemented.

In LADCO's summary of Class I areas impacted by sources from within the LADCO region, Indiana was determined to contribute to visibility impairment in this Class I area. SESARM has conducted modeling analyses to assist in developing RPGs for the second implementation period. Based on LADCO's recent RH modeling, results for this Class I area and nearby Class I areas (Joyce Kilmer - Slickrock Wilderness Area) show 2014-2018 baseline monitored values, as determined through the IMPROVE monitoring data, nearly match the modeled results from the base-year 2016 future year 2028 modeling.

Graph 23-6 Great Smoky Mountains URP Glidepath - 2016 Base-Year



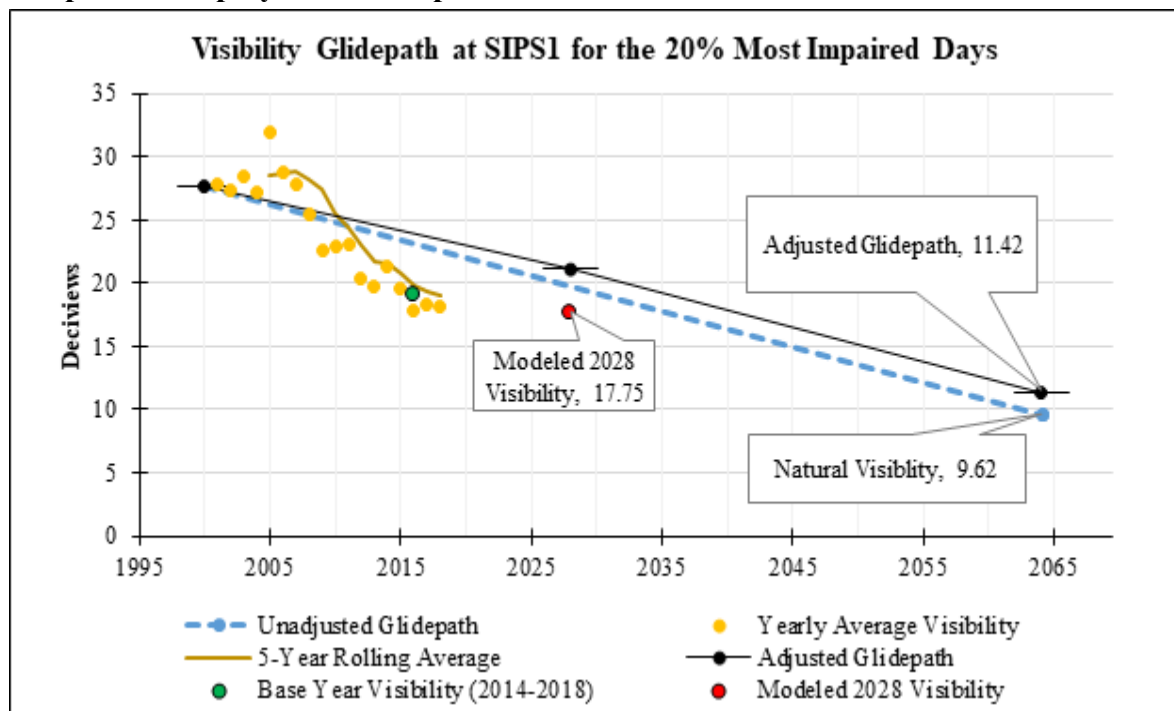
The monitoring and modeling clearly shows that visibility impairment at Great Smoky Mountains and Joyce Kilmer - Slickrock Class I areas is adequately addressed at this time. Therefore, no further analysis for this SIP is necessary.

23.6 Sipsey National Wilderness Area - Alabama

As demonstrated in the “2013 Alabama Regional Haze Mid-Course Review,” dated June 5, 2014, 2011 actual emissions were evaluated against the projected 2018 VISTAS inventory to ensure emissions continued to move in a downward trend to meet the 2018 RPGs. The results showed substantial emission reductions from several control programs implemented during the first planning period from controls currently in place (CSAPR, BART, MATS, etc.). As such, additional controls both considered in Alabama’s Regional Haze SIP as well as controls not considered (CSAPR Update) will continue to support progress in reducing emissions and improving visibility.

SESARM has conducted modeling analyses to assist in developing RPGs for the second implementation period. The IMPROVE monitoring data analyzed shows 2014-2018 baseline monitored values nearly match the modeled results from the base-year 2016 - future year 2028 modeling, indicating the Class I area is well ahead of its uniform rate of progress goals.

Graph 23-7 Sipsey URP Glidepath - 2016 Base-Year



Indiana has not been contacted by Alabama regarding consultations for this area and believes that no further analysis for a long-term control strategy is necessary at this time.

23.7 James River Face National Wilderness Area, Shenandoah National Park, Dolly Sods/Otter Creek National Wilderness Areas - Virginia and West Virginia

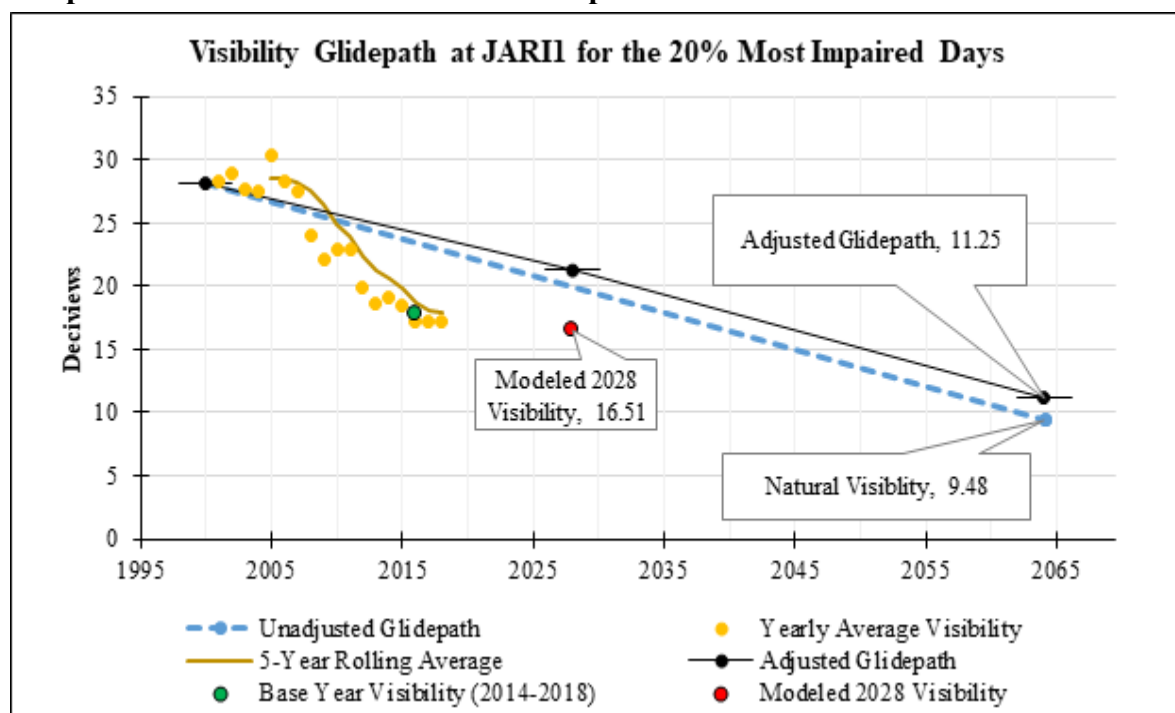
In the MRPO summary of Class I areas impacted by sources from within the MRPO for the first implementation period, Indiana was determined to contribute to visibility impairment in these more distant Class I areas. However, the VISTAS analyses conducted showed that the results of the long-term strategy developed by the States provided anticipated visibility improvements below the glidepath. In addition, the four-factor analyses performed by the VISTAS states indicated that controls closer to the Class I areas provided the most effective reductions. Indiana concurred with these conclusions, so no specific requirements were attributed to Indiana.

Virginia reported that visibility at the James River Face Wilderness Area and Shenandoah National Park had significantly improved since 2000. More recent data indicated that both Class I areas were meeting their RPGs and expected future reductions in SO₂ emissions as discussed in the “Commonwealth of Virginia State Implementation Plan Revision: Regional Haze Five-Year Periodic Report 2008-2013,” dated November 2013 would serve to continue this downward trend in the coming years. Since sulfate was identified as the major contributor to regional haze most emission reduction control strategies have been focused on reducing SO₂ from EGUs and industrial boilers. The “West Virginia State Implementation Plan Revision: Regional Haze 5-Year Periodic Report (Covering 2008-2013) Describing Progress Towards the Reasonable Progress Goals for visibility in Class I

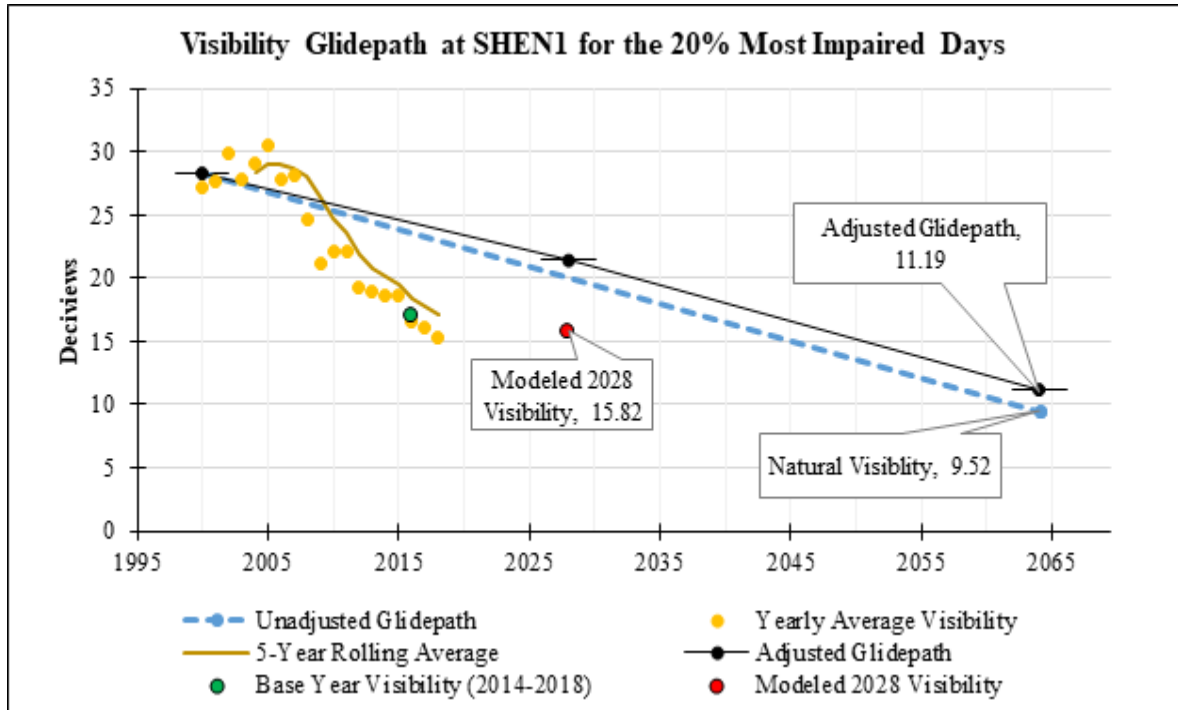
Federal Areas and Determination of Adequacy of Existing Implementation Plan,” dated April 2013, reported the same conclusions for the Dolly Sods and Otter Creek Wilderness Areas regarding visibility and progress towards 2018 goals. In 2009 actual EGU emissions were below what was predicted for 2009 and 2010 and 2011 EGU emissions were below what was predicted for 2018.

In the LADCO summary of Class I areas impacted by sources from within LADCO, Indiana was determined to contribute to visibility impairment in these more distant Class I areas. Since that time, SESARM has conducted several analyses to assist in developing reasonable progress goals for the second implementation period. The results of the long-term strategy developed by the states and SESARM provide anticipated visibility improvements below the glidepath. Graphs 23-8, 23-9, and 23-10 show the glidepaths for each of these areas. Results for all Class I areas analyzed show 2014-2018 baseline monitored values, as determined through the IMPROVE monitoring data, nearly match the modeled results from the base-year 2016 - future year 2028 modeling. The glidepath data for the graphs can be found in the LADCO RH modeling TSD and modeling files.

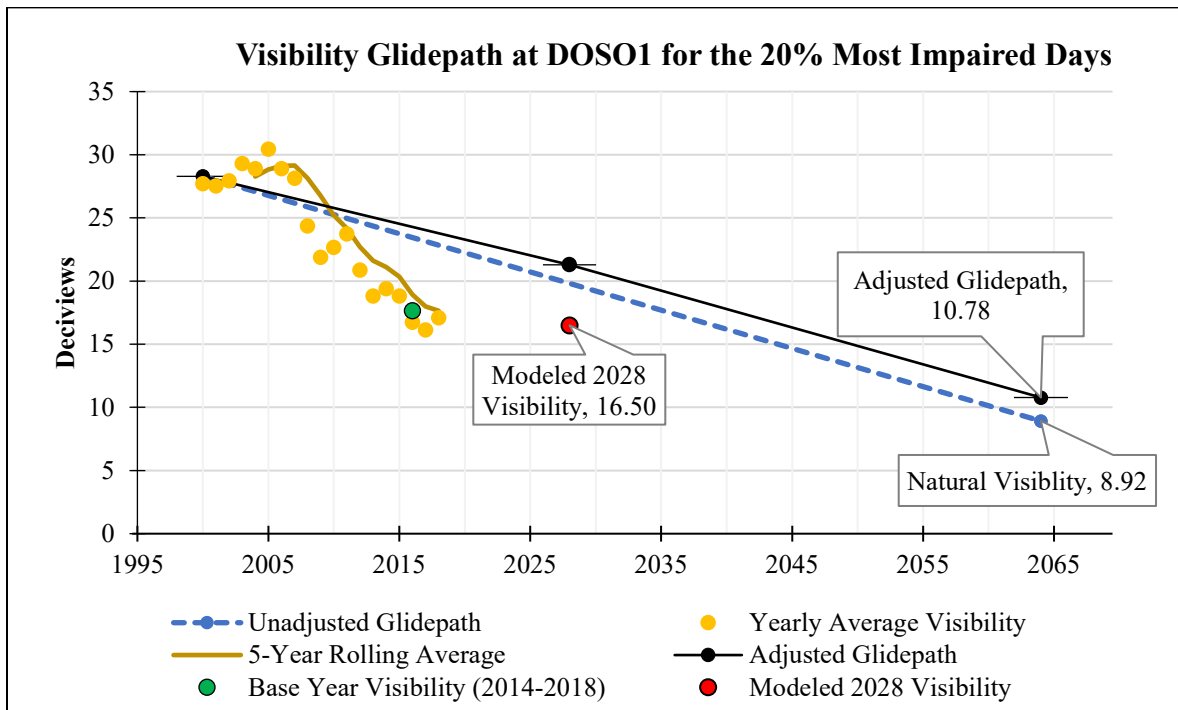
Graph 23-8 James River Face URP Glidepath - 2016 Base-Year



Graph 23-9 Shenandoah URP Glidepath - 2016 Base-Year



Graph 23-10 Dolly Sods URP Glidepath - 2016 Base-Year

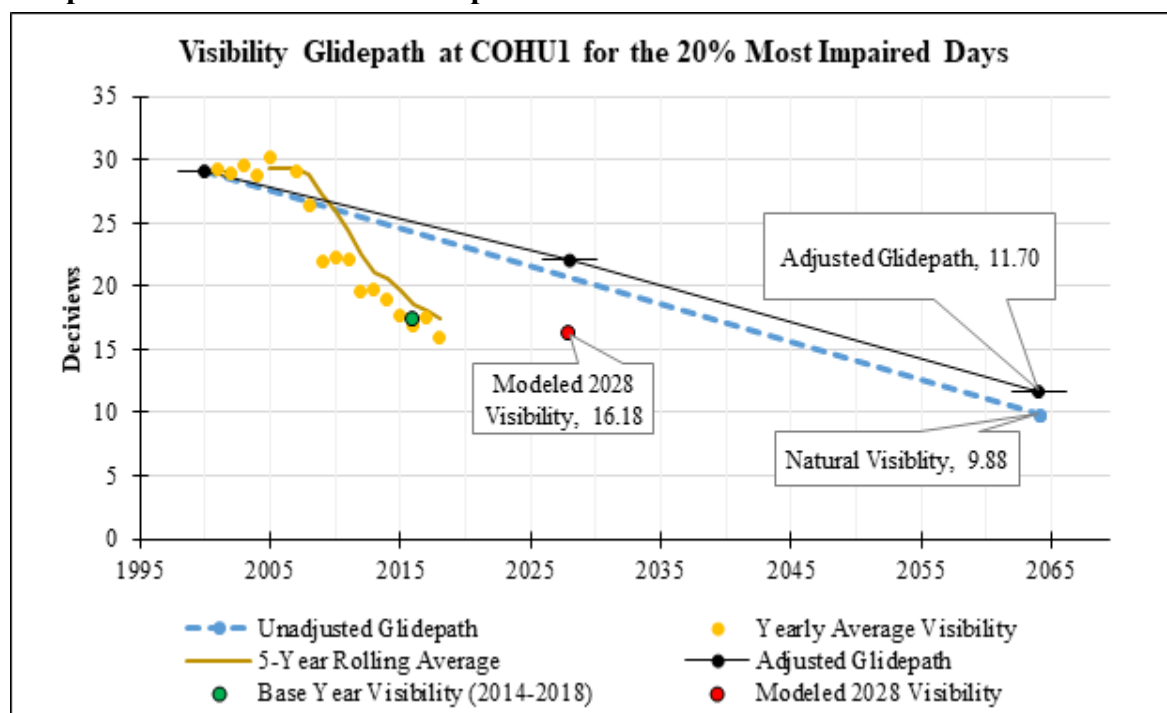


Neither Virginia nor West Virginia contacted IDEM to participate in consultations for these areas. The four-factor analyses performed by the SESARM states and resulting long term strategies indicate that controls closer to the Class I areas provide the most effective reductions at this time. Additionally, the long-term strategies provide anticipated visibility improvements below the glidepaths. Indiana concurs with these conclusions.

23.8 Cohutta Wilderness Area Georgia

These areas were identified in early LADCO modeling and other analyses as being impacted by Indiana sources. Indiana was invited to participate in the consultation process for these areas and attended the conference phone calls. Metro 4/SESARM notified IDEM that they had identified three of Indiana's EGUs (Duke Gibson, AEP Rockport, and AES Petersburg) as having possible visibility impacts. Results for all Class I areas analyzed show 2014-2018 baseline monitored values, as determined through the IMPROVE monitoring data, nearly match the modeled results from the base-year 2016 - future year 2028 modeling.

Graph 23-11 Cohutta URP Glidepath - 2016 Base-Year



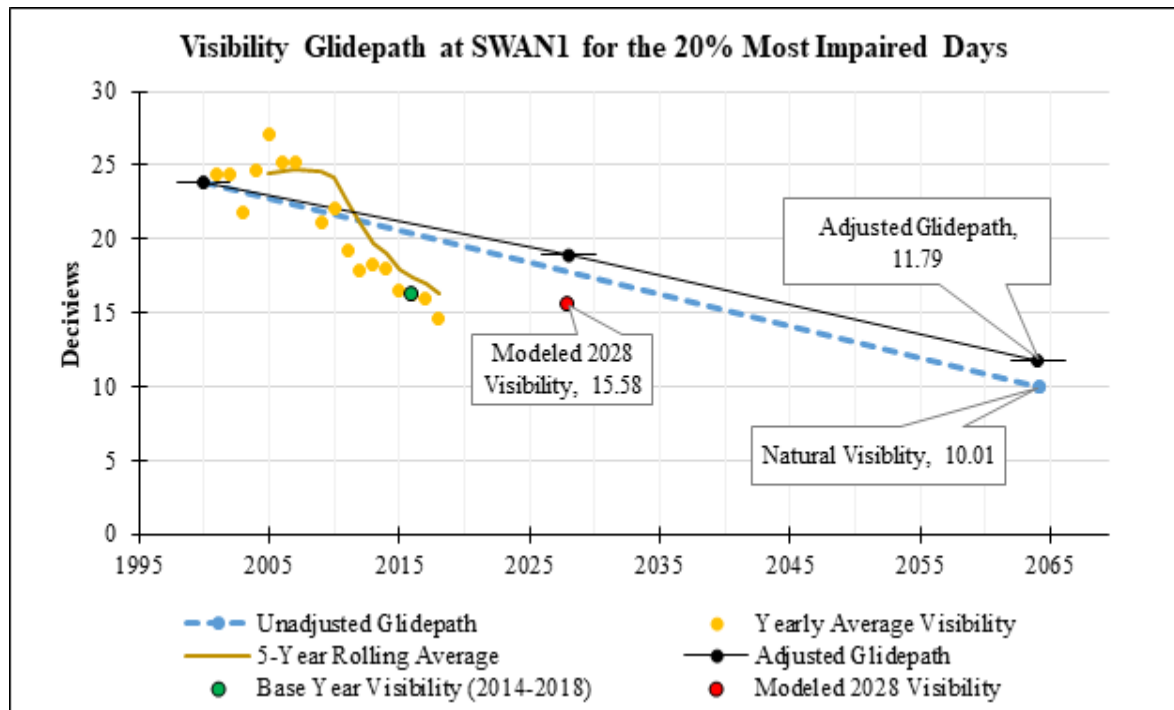
Indiana has not been contacted by Georgia regarding consultations for this area and believes that no further analysis for a long-term control strategy is necessary at this time.

23.9 Swanquarter, Linville Gorge and Shining Rock - North Carolina

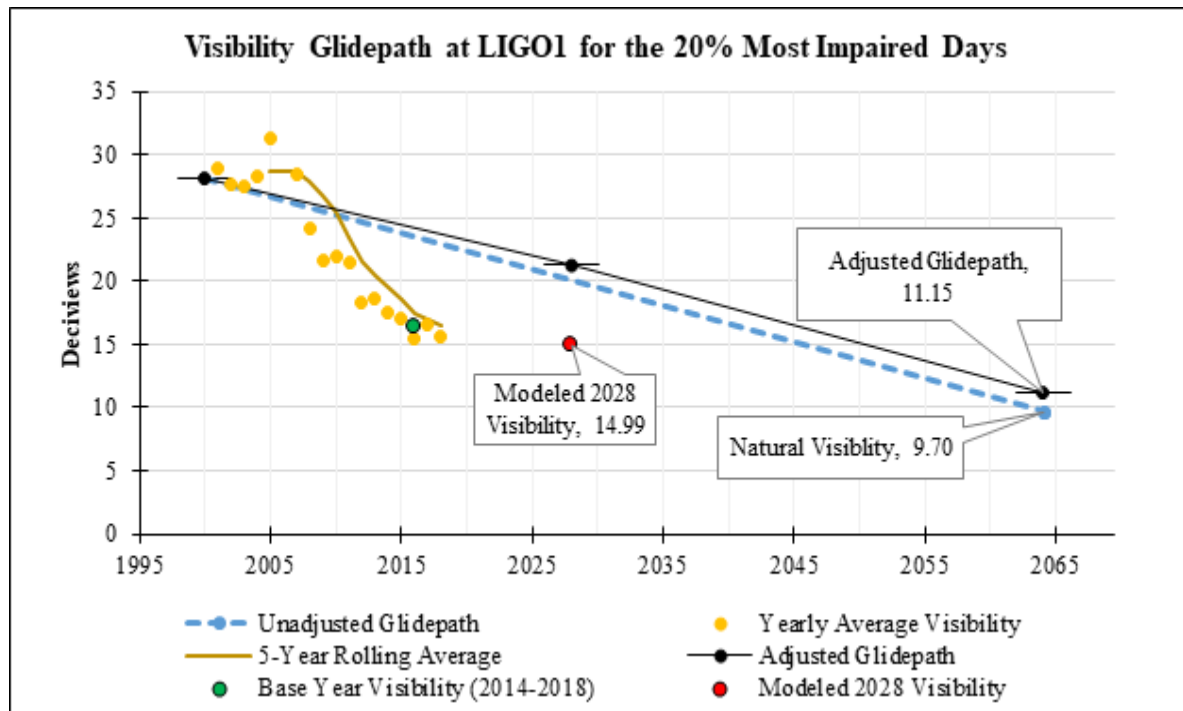
These areas were identified in VISTAS and LADCO modeling as being impacted by Indiana sources. Indiana participated in the consultation process for these areas through VISTAS emails, webinars and conference phone calls. Graphs 23-12 through 23-14 show

glidepaths resulting from the long-term strategies developed by the states, which illustrate that all the Class I areas are projected to meet their reasonable progress goals in 2028. LADCO modeling results for these North Carolina Class I areas analyzed show 2014-2018 baseline monitored values, as determined through the IMPROVE monitoring data, nearly match the modeled results from the base-year 2016 - future year 2028 modeling.

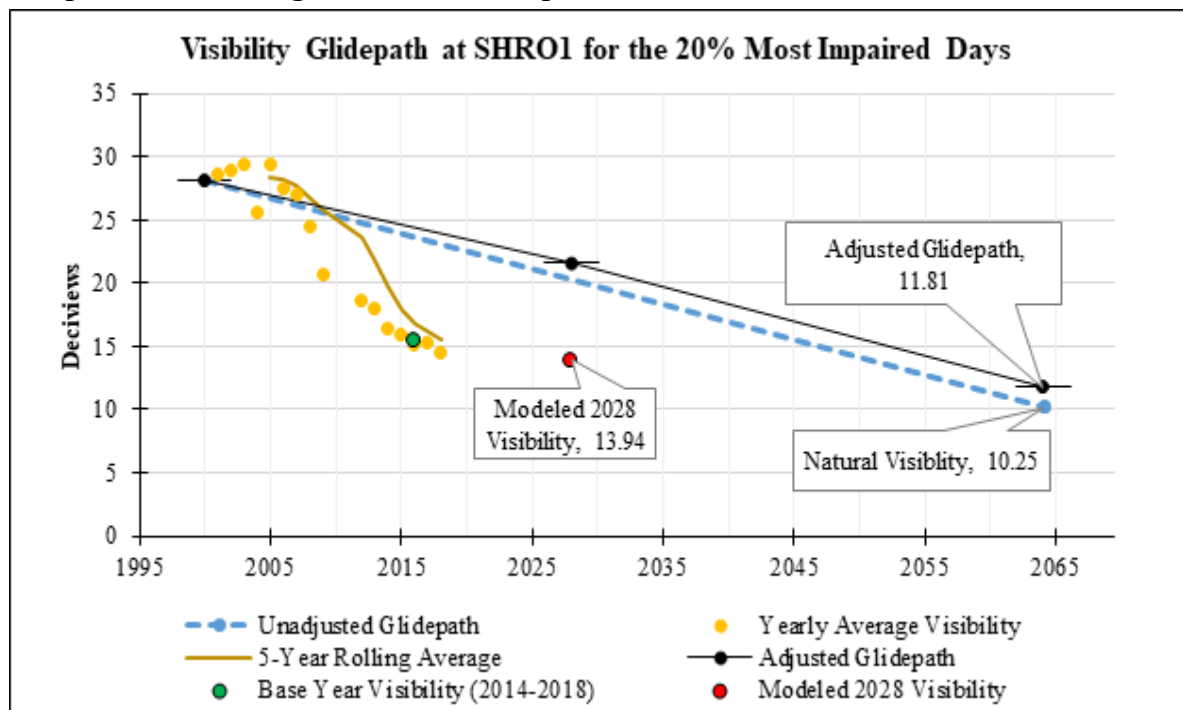
Graph 23-12 Swanquarter URP Glidepath - 2016 Base-Year



Graph 23-13 Linville Gorge URP Glidepath - 2016 Base-Year



Graph 23-14 Shining Rock URP Glidepath - 2016 Base-Year



Indiana has not been contacted by North Carolina regarding further consultations for these areas besides the VISTAS consultations, therefore Indiana believes that no further analysis for long-term control strategies is necessary at this time. Based on the emissions reductions from the Indiana's sources and LADCO's source apportionment modeling (described in

more detail in Section 24 of this document), Indiana concurs that substantial emission reductions have occurred over the past decade and additional emission reductions are anticipated throughout the second implementation period for the RH Rule. Therefore, relying on current and anticipated emission reductions and reduced visibility impairment from Indiana sources, as determined by LADCO's source apportionment modeling, this represents the best approach for addressing visibility impairment in these VISTAS Class I areas and no further analysis for this SIP is necessary.

23.10 Caney Creek and Upper Buffalo National Wilderness Areas, and Hercules-Glades and Mingo National Wilderness Areas - Arkansas and Missouri

Southwestern Indiana was included in the area of influence found to impact these areas, so the controls in existence in each state's 2002 inventory, those installed after 2002, and controls planned out to 2018, were analyzed. The results showed that a large majority of these sources would be controlled by 2018, which would aid in the progress toward reaching the states' RPGs. Glidepaths resulting from the long-term strategies developed by these states showed that all the Class I areas were projected to meet their reasonable progress goals in 2018. The states, therefore, concluded that no reductions were necessary from Indiana for the first implementation period.

According to the "State of Missouri Regional Haze Plan 5-Year Progress Report: A Missouri State Implementation Plan Revision," dated May 2014, emissions data reported to the NEI for 2005, 2008, and 2011 from the major source categories for the primary pollutants that affect visibility were compared to evaluate the emissions progress made for Missouri's 5-year progress report. The results of this analysis demonstrated an overall downward trend in visibility impairment that was expected to continue in the coming years as more federal regulations were implemented. The visibility and pollutant trends from Missouri's three monitoring sites also indicated an overall decreasing trend in visibility impairment. The available monitoring data was extrapolated to 2018 to predict whether the RPGs for each area would be met by 2018. These extrapolations did show all areas would exceed the established goals by 2018.

The "State of Arkansas: State Implementation Plan Review for the Five-Year Regional Haze Progress Report," dated May 2015, reported that the current 5-year average indicated that as of 2011, Caney Creek Wilderness area had achieved 73% of its visibility impairment reduction goal of 3.88 dv and Upper Buffalo Wilderness area has achieved 66% of its visibility impairment reduction goal of 3.75 dv by 2018. Therefore, Arkansas concluded that the emission reductions were on track to meet or exceed the 2018 goals.

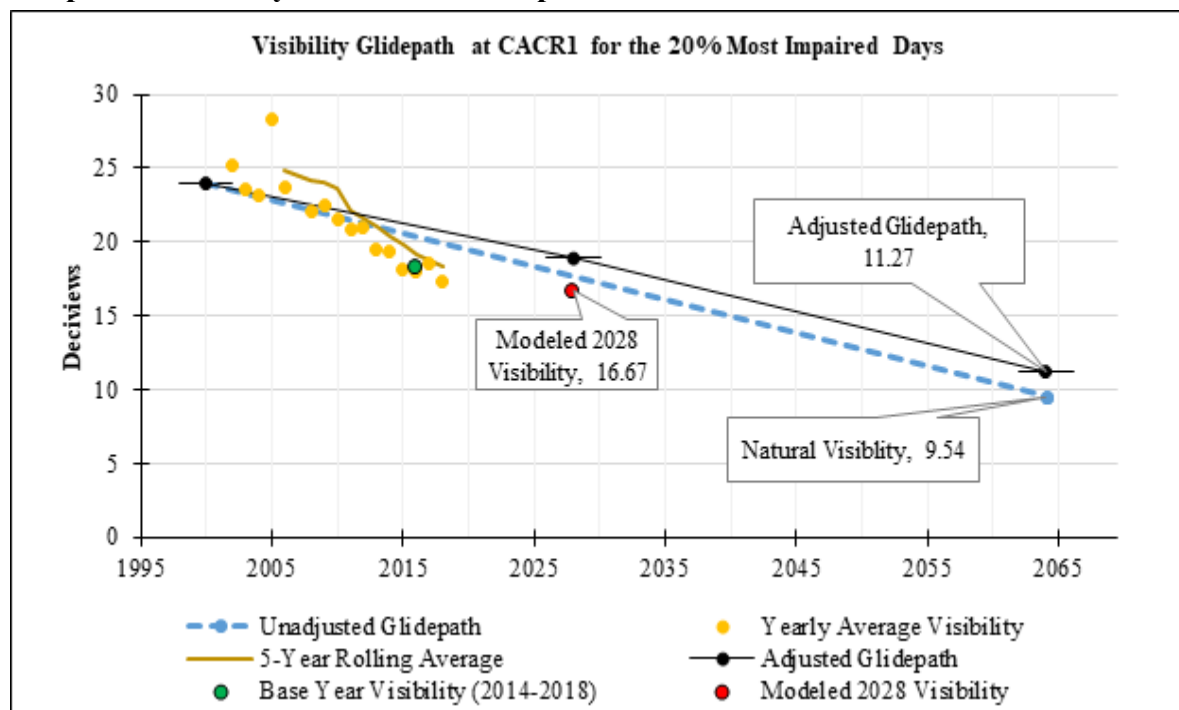
Arkansas and Missouri notified IDEM that they had identified two of Indiana's EGUs (Duke Gibson and AEP Rockport) as potentially impacting visibility at Class I areas within their state/region for the second implementation period for regional haze. These areas were identified in LADCO modeling for the second implementation period as being impacted by Indiana sources. Indiana participated in the consultation process for these areas by email and attended conference phone calls. These correspondences, detailing the consultation with each state, can be found in Appendix K. LADCO visibility modeling results were

delayed so the modeled visibility impacts on Class I areas were not available until June of 2021 which prevented more frequent consultations.

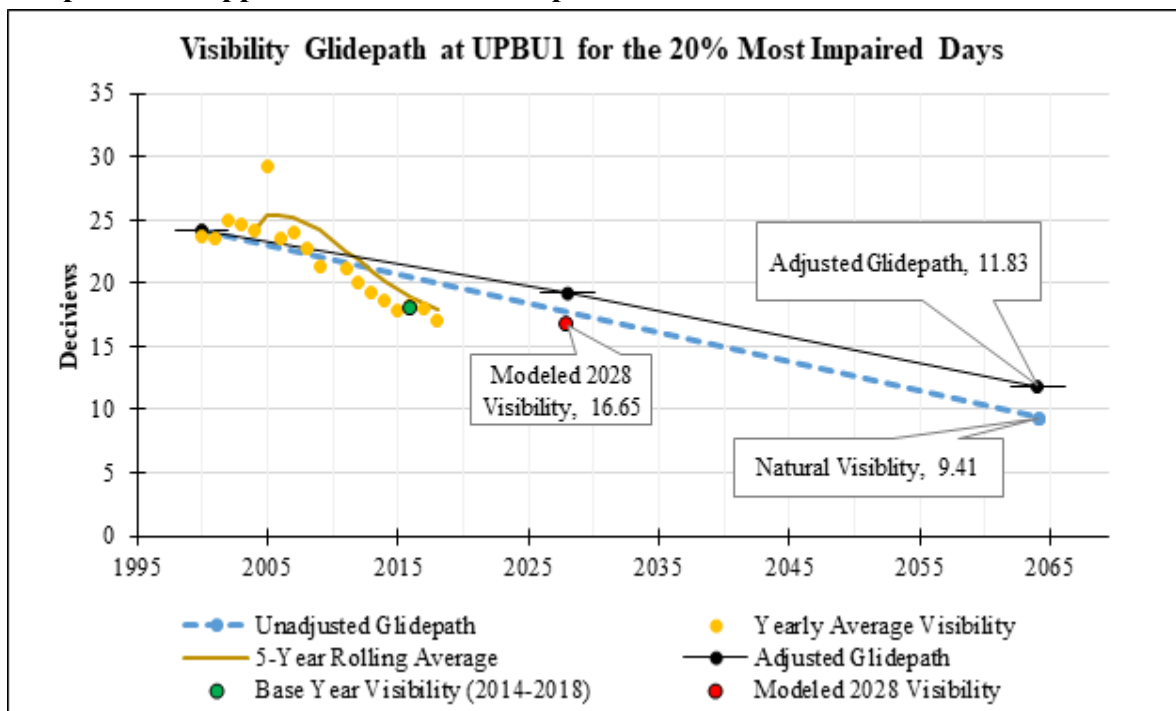
Graphs 23-15 through 23-18 show glidepaths resulting from the long-term strategies developed by the states, which illustrate that all the Class I areas are projected to meet their reasonable progress goals in 2028. In fact, results for all Class I areas analyzed show 2014-2018 baseline monitored values, as determined through the IMPROVE monitoring data, nearly match the modeled results from the base-year 2016 - future year 2028 modeling. Source apportionment modeling confirms that the Duke Gibson and AEP Rockport facilities have visibility impacts that total less than 1% of the total visibility impacts at any of the Class I areas in Missouri or Arkansas. The glidepath data for the graphs can be found in the LADCO RH modeling TSD and modeling files, dated June 17, 2021 in Appendix L of this document.

Based on the current and projected emissions reductions from the Indiana EGUs specified by Arkansas and Missouri and LADCO's source apportionment modeling results for Duke Gibson and AEP Rockport on visibility impacts on Class I areas (described in more detail in Section 24 of this document), Indiana believes no further analysis for this SIP is necessary as a result of the substantial emission reductions that have occurred over the past decade and additional emission reductions anticipated throughout the second implementation period for the RH Rule.

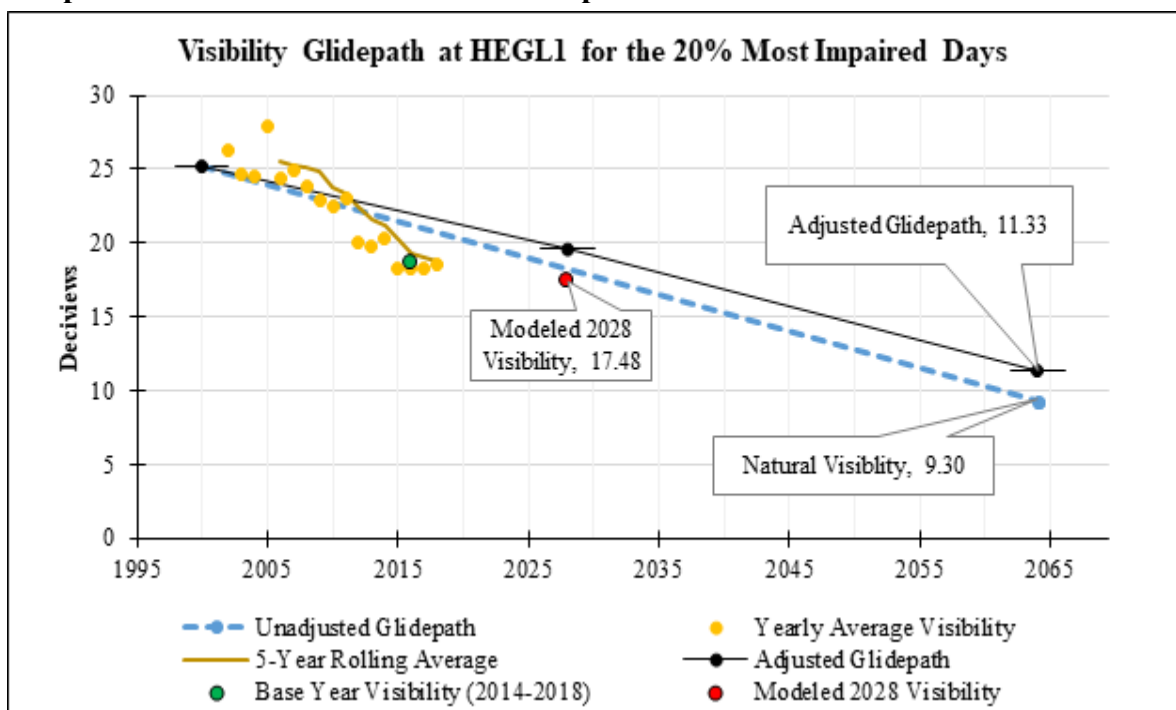
Graph 23-15 Caney Creek URP Glidepath - 2016 Base-Year



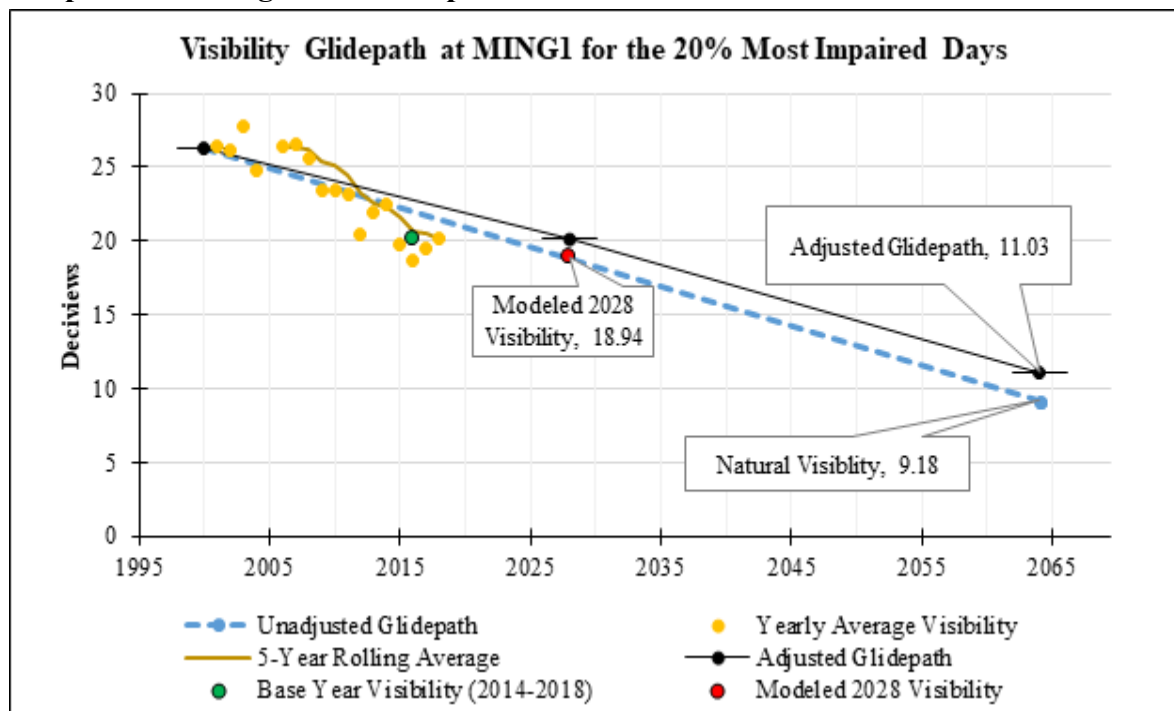
Graph 23-16 Upper Buffalo URP Glidepath - 2016 Base-Year



Graph 23-17 Hercules-Glades URP Glidepath - 2016 Base-Year



Graph 23-18 Mingo URP Glidepath - 2016 Base-Year



23.11 Brigantine National Wilderness Area, NJ; and Lye Brook National Wilderness Area, VT (MANE-VU)

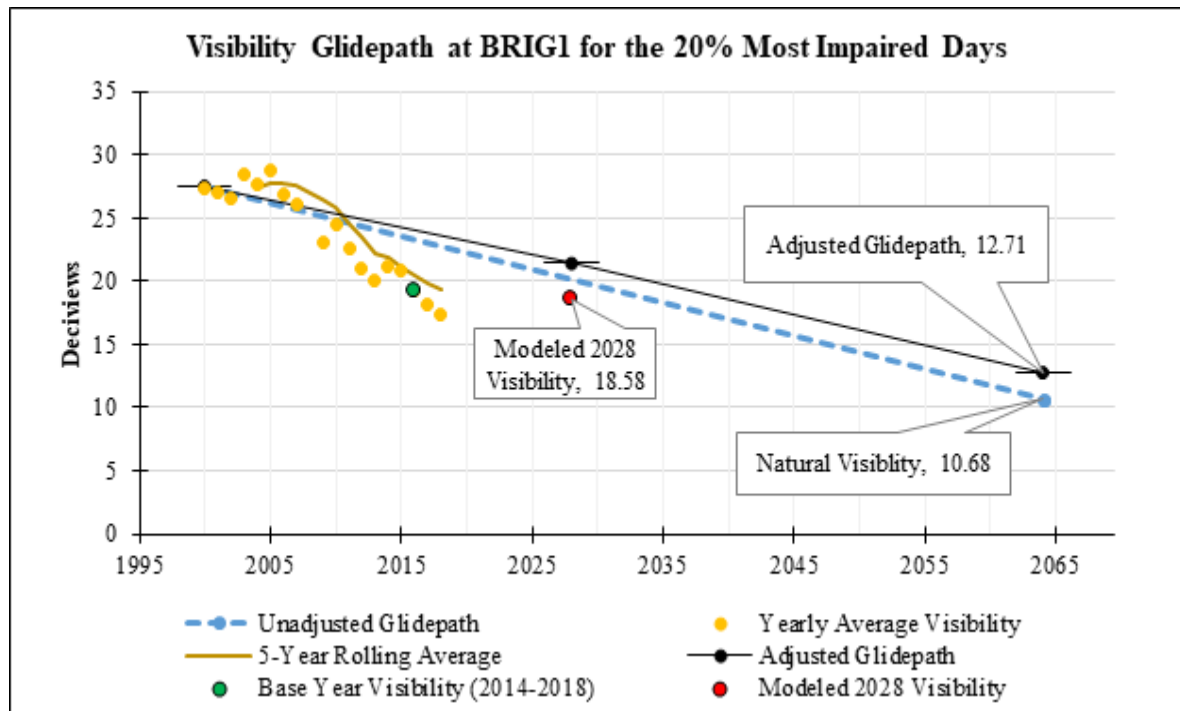
MANE-VU released “2016 Updates to the Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas - Methodology for Source Selection, Evaluation of Control Options, and Four Factor Analysis” which supported requests of states outside that area to examine controls for specific types of sources. This document is available online at the MANE-VU website, https://s3.amazonaws.com/marama.org/wp-content/uploads/2019/09/13095234/FINAL_Updates_to_4Factor_Reasonable_Progress_Report_2016_01_31.pdf

LADCO conducted modeling to evaluate the various levels of controls in place or planned between 2018 and 2028. These results showed that for the northeastern Class I areas, controls already implemented, and on-the-books will result in achievement of reasonable progress goals. These controls along with federal programs implemented over the first implementation period, such as the 2010 SO₂ NAAQS, MATS, Boiler MACT, Tier 3 Program, etc., meet the requirements for control strategies of NO_x and SO₂ emissions and, therefore do not impede these areas in meeting their 2028 reasonable progress goals. LADCO modeling has shown low visibility impacts from Indiana sources on the MANE-VU Class I areas. Indiana, along with the other LADCO states, participated in early consultations with MANE-VU in 2017 and 2018.

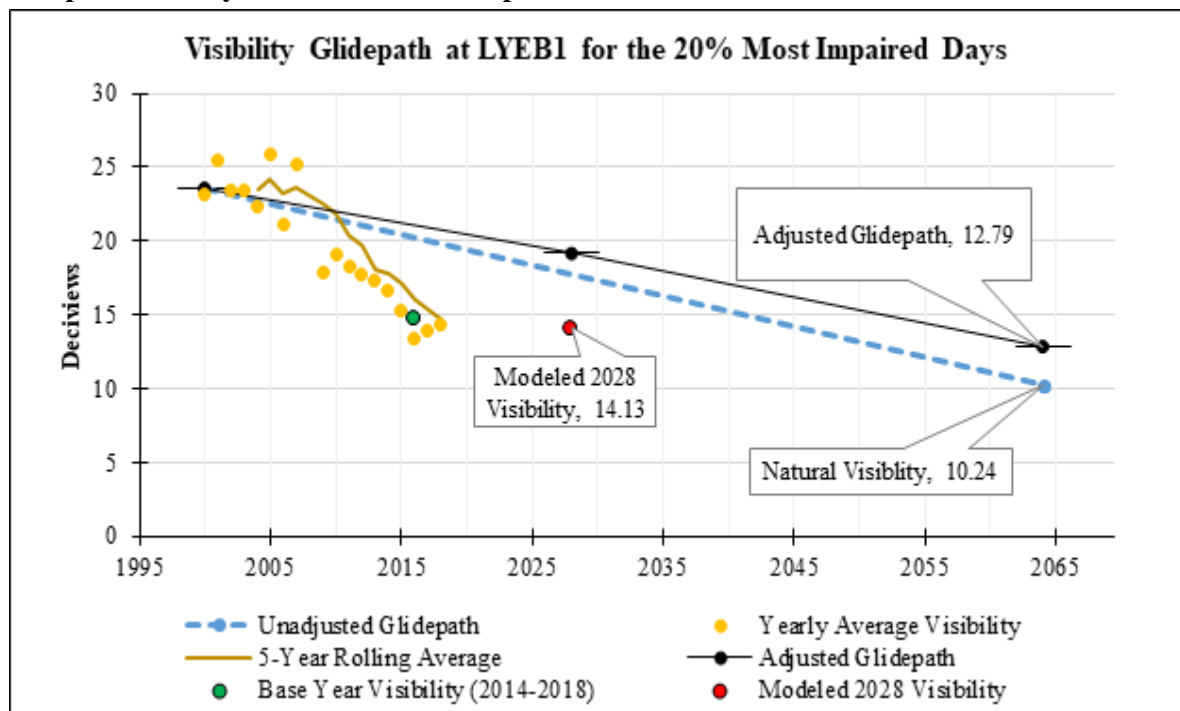
Results for MANE-VU Class I areas analyzed show 2014-2018 baseline monitored values, as determined through the IMPROVE monitoring data, nearly match the modeled results from the base-year 2016 - future year 2028 modeling. Indiana concurs that this is the best

approach for addressing visibility impairment at the MANE-VU Class I areas as substantial emission reductions have occurred over the past decade and additional emission reductions are anticipated throughout the second implementation period for the RH Rule. Therefore, no further analysis for this SIP will be taken.

Graph 23-19 Brigantine URP Glidepath - 2016 Base-Year



Graph 23-20 Lye Brook URP Glidepath - 2016 Base-Year



LADCO RH modeling confirms that all sources in Indiana have visibility impacts that total less than 2.5% of the total visibility impacts at either of the Class I areas in New Jersey and Vermont. Therefore, Indiana does not believe at this time that it can commit to any particular course of action until it is determined, through the above work and further discussions, what actions may be appropriate to meet reasonable progress goals given Indiana’s marginal impact on those areas.

24.0 SOURCE APPORTIONMENT MODELING

LADCO’s source apportionment modeling looked at the individual impacts from emission sectors within the state. Due to its close proximity to Indiana, Mammoth Cave National Park in Kentucky shows the greatest visibility impact from Indiana, as was expected. It is worth noting that Indiana’s modeled visibility impacts, based on 2016 emissions, had reduced visibility impacts on most all surrounding Class I areas when compared with modeling conducted using 2011 base emissions. This fact is further confirmed in the decrease in monitored visibility impairment over this period of time. Additional expected emission reductions before 2028 will decrease the monitored visibility impacts even further. All other visibility impacts from Indiana on the identified VISTAS Class I areas are at approximately 6% or below. It should be noted Indiana’s visibility impacts are even less at the northern Class I areas and Class I areas located in Missouri and Arkansas.

24.1 Summary of EGU Source Apportionment Modeling for Indiana

Table 24-1 shows all Indiana EGUs (IN EGU) contributions to total light extinction at all Class I areas modeled. All Class I areas of concern had contributions to visibility

impairment from Indiana's EGUs of less than 3.6%, with the exception of modeled visibility impacts at Mammoth Cave National Park, the total contribution from all Indiana EGUs is 6.9%.

Table 24-1 Indiana EGU Visibility Impacts on Class I Areas

Class I Area	Total Class I Light Extinction (Mm⁻¹)	IN EGU Nitrate Impact (Mm⁻¹)	IN EGU Sulfate Impact (Mm⁻¹)	Total IN EGU Impact (Mm⁻¹)	Total IN EGU Impact (%)
Mammoth Cave	74.18	0.963	4.128	5.091	6.9%
Sipsey	60.97	0.276	1.936	2.212	3.6%
Great Smoky Mountains/ Joyce Kilmer-Slickrock	51.02	0.187	1.502	1.689	3.3%
Dolly Sods/Otter Creek	54.03	0.064	1.543	1.607	3.0%
Cohutta	51.8	0.099	1.387	1.486	2.9%
Shenandoah	50.63	0.071	1.338	1.409	2.8%
Mingo	69.67	0.414	1.189	1.602	2.3%
James River	53.42	0.053	1.103	1.156	2.2%
Linville Gorge	45.73	0.018	0.919	0.937	2.1%
Hercules Glades	59.43	0.088	0.724	0.813	1.4%
Shining Rock	41.42	0.014	0.530	0.545	1.3%
Upper Buffalo	54.35	0.068	0.647	0.715	1.3%
Seney	57.36	0.153	0.460	0.613	1.1%
Lye Brook	42.86	0.042	0.353	0.395	0.9%
Caney Creek	54.4	0.05	0.377	0.427	0.8%
Brigantine	69.4	0.037	0.445	0.482	0.7%
Swanquarter	48.52	0.031	0.325	0.356	0.7%
Isle Royale	48.62	0.049	0.214	0.263	0.5%
Voyageurs	41.03	0.014	0.054	0.068	0.2%
Boundary Waters	40.51	0.022	0.048	0.07	0.2%

While Indiana's EGU contributions to total sulfate visibility impacts were higher compared to the total nitrate impacts on visibility, showing the sulfate influence in this portion of the country, Indiana's EGU contribution to total nitrate visibility impacts were less than 1% at all listed Class I areas with the exception of Mammoth Cave. Indiana considers a better representation of visibility impairments on the 20% most anthropogenically impaired days is to consider the total light extinction and compare with the source's combined emissions to determine impacts on visibility. Indiana's EGU future year visibility contribution as a percent of total emissions is projected to be higher as a result of the number of coal unit retirements statewide between 2016 and 2028; in terms of total mass contribution from Indiana's EGUs, overall emissions are much lower in 2028 versus the base year. As stated previously, overall visibility modeling demonstrates reasonable progress goals are being met and the RPG are well below the uniform rate of progress for all Class I areas of concern.

24.2 Summary of nonEGU Source Apportionment Modeling for Indiana

LADCO conducted source apportionment modeling for 27 tagged sources, of which Indiana had 9 tagged sources. Those sources categories/individual sources were: 1) Indiana non-point sources, 2) Rockport EGU, 3) Gibson EGU, 4) All other Indiana EGUs, 5) Indiana cement manufacturing facilities, 6) Indiana iron and steel facilities, 7) Indiana plastics and resin manufacturing facilities, 8) Indiana aluminum production facilities, 9) all other Indiana point sources. The Rockport EGU, Gibson EGU and all other Indiana EGUs were totaled to give the total Indiana EGUs visibility impact. The nine tagged source categories were added together to give the total visibility impacts from all Indiana anthropogenic sources.

Table 24-2 provides the percentage contribution of each of the source categories and individual tagged sources on Indiana's total visibility on each Class I area, except for the EGU sources that were tagged separately.

Table 24-2 Breakdown of Indiana Contribution Impacts by Source Category

Class I Area	Indiana Impact on Total Light Extinction (Mm⁻¹)	Cement Impact on Indiana's Total Light Extinction Impact (%)	Iron/Steel Impact on Indiana's Total Light Extinction Impact (%)	Plastics/ Resin Impact on Indiana's Total Light Extinction Impact (%)	Aluminum Impacts on Indiana's Total Light Extinction Impact (%)	All other Point Source Impacts on Indiana's Total Light Extinction Impact (%)
MACA	8.31	2.1%	7.9%	2.6%	1.5%	5.7%
SIPS	3.57	2.1%	8.8%	4.7%	2.1%	5.6%
DOSO	3.04	1.4%	12.3%	2.1%	1.0%	9.2%
GRSM	2.7	2.5%	8.1%	3.2%	1.8%	5.6%
SHEN	2.61	1.5%	13.8%	2.0%	1.0%	8.9%
COHU	2.47	2.4%	12.0%	3.5%	2.2%	6.2%
MING	2.85	1.5%	11.0%	5.5%	1.5%	6.1%
SENE	2.28	1.3%	29.0%	1.8%	0.6%	10.0%
JARI	2.02	1.1%	17.2%	2.0%	0.8%	7.1%
LIGO	1.33	0.7%	10.5%	3.4%	1.4%	5.0%
LYBR	1.0	1.4%	21.2%	2.0%	0.9%	8.6%
BRIG	1.62	1.0%	23.8%	1.3%	0.6%	10.3%
SHRO	0.89	1.1%	13.2%	3.5%	1.4%	5.8%
HEGL	1.24	1.4%	6.9%	3.7%	1.3%	5.2%
UPBU	1.06	1.5%	6.0%	3.7%	1.3%	4.9%
ISLE	0.94	1.0%	28.6%	1.4%	0.4%	10.2%
SWAN	0.89	1.3%	17.4%	1.7%	0.7%	9.6%
CACR	0.63	1.4%	6.4%	3.5%	1.2%	5.3%
BOWA	0.25	2.1%	17.9%	1.8%	0.8%	11.0%
VOYA	0.22	1.9%	26.9%	1.8%	0.8%	8.5%

While the percent contribution from several of the source categories is rather large, Indiana's portion of its contribution to the Class I area total light extinction is small. When broken down by source category, the visibility impacts on light extinction from most of the tagged source categories will not equate to more than one inverse megameter (Mm⁻¹) which is the equivalent to much less than one deciview.

25.0 20% CLEAREST DAYS ANALYSIS

Results for Class I areas analyzed show 2014-2018 baseline monitored values of the 20% clearest days, as determined through the IMPROVE monitoring data, are lower than the modeled visibility impacts at each Class I area for 2028, based on the 2011 emissions and nearly match the modeled results from the base-year 2016 - future year 2028 modeling. These results are similar to the 20% most anthropogenically impaired days and are proof of the consistency of the emission reductions realized throughout the country. The significance of the 2014-2018 monitored period is it marks the end of the first implementation period of the RH Rule and shows the progress at all Class I areas of improved visibility and no degradation of visibility on these days is anticipated. Table 25-1 details the monitored and modeled visibility results on the 20% clearest days which were taken from LADCO's RH modeling (completed in June of 2021) and the corresponding summary of modeled results spreadsheets can be provided by LADCO.

Table 25-1 Monitoring and Modeled Visibility Results for Class Areas (20% Clearest Days)

Site	2000-2004 Monitored Baseline (dv)	2009-2013 Monitored Baseline (dv)	2014-2018 Monitored Baseline (dv)	2011 base - 2028 Modeled Results (dv)	2016 base - 2028 Modeled Results (dv)
Boundary Waters	6.5	4.8	4.5	4.8	4.4
Voyageurs	7.2	5.7	5.3	5.7	5.3
Seney	7.1	5.5	5.3	5.4	5.2
Isle Royale	6.8	5.4	5.3	5.3	5.2
Hercules-Glades	12.8	11.0	9.7	10.1	9.1
Mingo	14.4	12.4	11.1	11.4	10.5
Caney Creek	11.2	9.8	8.0	9.1	7.6
Upper Buffalo	11.7	9.9	8.2	9.2	7.8
Mammoth Cave	16.5	13.7	11.3	12.0	10.5
Cohutta	13.7	10.9	8.1	9.4	7.6
Dolly Sods	12.3	9.0	6.7	7.8	6.3
Shenandoah	11.0	8.6	6.9	7.4	6.3
James River Face	14.2	11.7	9.5	10.1	8.8
Linville Gorge	11.1	9.7	7.6	8.5	7.2
Shining Rock	7.7	I/D	4.4	I/D	4.1
Swanquarter	12.3	10.0	10.6	10.9	10.2
Brigantine	14.3	12.3	11.3	11.2	10.8
Lye Brook	6.4	4.9	5.0	4.3	4.8
Great Smokey Mountains	10.1	10.7	8.4	9.3	7.9
Sipsey	9.6	12.9	10.8	11.6	10.1

Note: Shining Rock had incomplete data (I/D) for 2011 and therefore no results were determined in the 2011-2028 LADCO Modeling.

While this fact does not absolve states from addressing key elements of the RH Rule, it does emphasize the emissions reductions that have occurred throughout the country have realized monitored visibility benefits and are well ahead of future projections of visibility impacts at the Class I areas for 2028. The steady decline of visibility impacts at the Class I areas from anthropogenic emissions are significant and indicate that states are taking the necessary steps to remain ahead of the schedule in the glidepaths and are projected to approach natural visibility conditions ahead of 2064.

26.0 DECISION ON WHAT CONTROL MEASURES ARE NECESSARY TO MAKE REASONABLE PROGRESS

A reasonable progress analysis was conducted for Indiana's EGU sources and four-factor analyses were conducted for the non-EGU sources that met IDEM's four-factor analysis selection criteria as required by the RH Rule. While the results of these analyses varied from source to source with respect to the relevant factors considered, significant SO₂ and NO_x

emissions reductions from Indiana's highest emitting sources and visibility improvement at Class I areas impacted by Indiana's contributing sources have exceeded the state's reasonable progress goals for the first implementation period. Since the RH program is an iterative program that provides states with the flexibility to develop a cohesive strategy that demonstrates reasonable progress over time toward natural visibility by 2064, Indiana offers the following weight of evidence demonstration consistent with this overarching principle to support the state's decision not to require additional control measures for the selected sources.

According to the EPA RH SIP Guidance Document, the RH Rule allows a state to demonstrate, based on careful consideration of relevant factors for its selected sources, that no additional measures are necessary to make reasonable progress in the second implementation period. The goal of the RH program is to improve visibility over time; therefore, it is reasonable for a state to consider whether and by how much an emission control measure would help achieve that goal. Likewise, it is reasonable that such information on visibility benefits be considered in light of other factors that may weigh for or against the controls at issue. Such a balancing of outcomes is consistent with CAA section 169A(b)(2), which states that SIPs must contain elements as may be necessary to make reasonable progress towards meeting the national visibility goal. Thus, EPA interprets the CAA and the RH Rule to allow a state reasonable discretion to consider the anticipated visibility benefits of requiring selected sources to install additional control measures along with the other factors when determining whether control measures are necessary to make reasonable progress.

Section 51.308(f)(2) of the Regional Haze Rule requires SIPs to include the "enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress as determined pursuant to [51.308](f)(2)(i) through (iv)." This provision requires SIPs to include enforceable emission limitations and/or other measures to address regional haze, deadlines for their implementation, and provisions to make the measures practicably enforceable including averaging times, monitoring requirements, and record keeping and reporting requirements. There is a considerable body of applicable EPA rules, EPA guidance, and EPA-approved state practices on the topic of practicably enforceable emission limits. The RH program is implemented through SIPs, and the second implementation period SIPs must include the emission limits and other measures necessary to assure reasonable progress in order to comply with the applicable statutory and regulatory requirements. If a state determines that an in-place emission control at a source is a measure that is necessary to make reasonable progress and there is not already an enforceable emission limit corresponding to that control in the SIP, the state is required to adopt emission limits based on those controls as part of its LTS in the SIP via the RH second implementation period plan submission.

The LTS can be said to include those controls only if the SIP includes emission limits or other measures (with associated averaging periods and other compliance program elements) that effectively require the use of the controls. If the current SIP includes emission limits and other measures that would not ensure the continued use of that technology with good operating practices, then the limits and compliance program elements in the LTS must be revised via the RH second implementation period plan submission. Inclusion in the SIP makes the emission limits permanent (meaning they cannot be subsequently revised without an EPA approved SIP revision) and federally enforceable.

26.1 Impact of Sulfur Dioxide and Nitrogen Oxides Emissions Reductions on Reasonable Progress Goals

SO₂ and NO_x emissions reductions from Indiana's highest emitting sources contributing to visibility impairment at Class I areas outside the state has had a significant impact on Indiana's ability to meet the first implementation period reasonable progress goals. As such, Indiana had concluded that the reasonable progress analysis for Indiana's EGU selected sources and four-factor analysis conducted for the remaining non-EGU selected sources do not provide adequate evidence for the state to require additional control measures considering the significant progress already made towards achieving the national visibility goal. Indiana has determined that none of the controls identified in the four-factor analyses were cost effective for the small amount of emission reductions that would be realized. Indiana has demonstrated that visibility improvements for this second implementation period for regional haze is well ahead of reasonable progress goals. The following evaluation of Indiana's point source SO₂ and NO_x emissions demonstrate that additional control measures are not necessary to make reasonable progress in the second implementation period.

26.1.1 Sulfur Dioxide Emissions Reductions

Indiana's inventory of actual emissions reported from contributing sources of SO₂ in 2007 through 2019 shows a definite downward trend as illustrated in Graph 26-1. The SO₂ emissions illustrated in this graph represent Indiana's combined emissions from its point source category. All of the selected sources for evaluation are included in this category which offers a focused evaluation of Indiana's SO₂ emissions from the sources of interest. State and federal control measures phased in and implemented over the course of the first implementation period has resulted in considerable SO₂ emission reductions. The most substantial reductions took place in the year corresponding between 2014 and 2017 as shown by the emissions information listed in Table 26-1 and illustrated by the trend line in Graph 26-1 on the next page for actual (reported) SO₂ emissions from the point source category in Indiana.

These reductions are due primarily to regulations focused on reducing SO₂ emissions from coal burning power plants and other large sources, such as those selected for four-factor analysis evaluation. They are the largest emitters of SO₂. Federal programs such as the 2010 SO₂ NAAQS, CSAPR, MATS and the Regional Haze Rule itself, caused power plants to develop and implement control measures aimed at reducing SO₂ emissions to comply with the requirements set forth in these regulations for the first implementation period. In addition to the federal programs previously mentioned for Indiana's EGUs, there are industry specific NSPS promulgated or updated that target SO₂ emissions from affected non-EGUs as well. NSPS are reviewed every 8 years. The federal programs controlling SO₂ emissions from selected sources are discussed in the reasonable progress and four-factor analyses.

Although SO₂ controls were in place by 2009 when CAIR became effective, SO₂ emissions began to decrease in 2010 when the EPA strengthened the federal SO₂

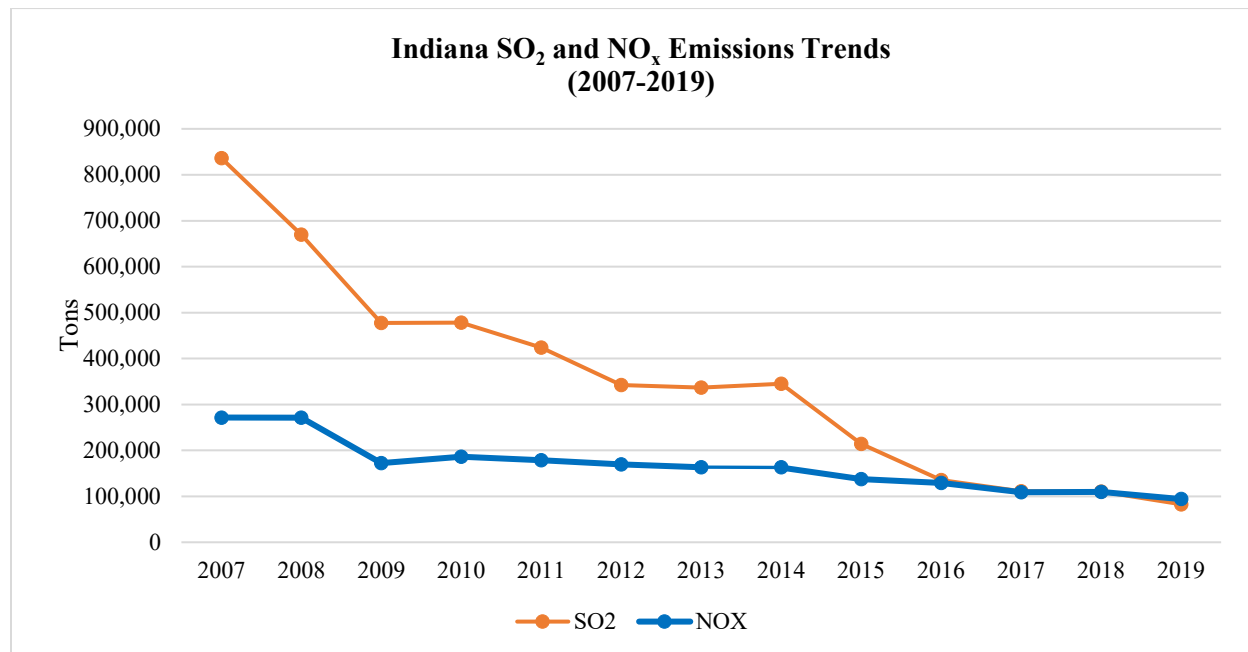
standards, establishing a new one-hour primary standard. In fact, Indiana has attained the 1-hr SO₂ standard in all but 1 area (Huntington County). This includes areas surrounding all Indiana EGUs and non-EGUs throughout the state. SO₂ emissions leveled off between 2012 and 2014 with the most significant reductions occurring between 2014 and 2017, as a result of CSAPR being upheld in 2014. Phase 2 budget reduction took effect in 2015 for CSAPR. Actual SO₂ emissions reported from the point source category decreased significantly over this 3-year timeframe with a dramatic decrease of 68% reduction in emissions and nearly 90% reduction over the entire 13-year evaluation period. SO₂ emissions continued to decrease after 2017 for the first implementation period (2007 - 2018) and have yet to plateau.

Additional reductions are expected as a result of federal regulations to be implemented over the course of the next few years which will result in an even greater improvement in visibility than anticipated by 2028.

Table 25-1 Actual (Reported) SO₂ and NO_x Emissions from Contributing Point Sources in Indiana for 2009-2019

Pollutant	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
SO ₂ (tons)	836,260	669,440	477,699	478,277	423,612	342,319	336,596	345,314	214,181	135,474	110,791	110,086	82,677
NO _x (tons)	271,556	271,495	172,588	186,053	178,924	169,275	163,561	162,831	137,275	129,334	109,075	109,751	94,002

Graph 26-1 Actual (Reported) SO₂ and NO_x Emission Trends from Contributing Point Sources in Indiana for 2007-2019



26.1.2 Nitrogen Oxides Emissions Reductions

NO_x emissions from the point source category in Indiana also show a definite downward trend line also as illustrated in Graph 26-1 above. Federal programs such as the NO_x SIP Call, CSAPR, and the Regional Haze Rule, caused power plants to develop and implement control measures aimed at reducing NO_x emissions to comply with the requirements set forth in these regulations for the first implementation period. In addition to the federal programs previously mentioned for Indiana's EGUs, there are industry specific NSPS promulgated or updated that target NO_x emissions from affected non-EGUs as well. NSPS are reviewed every 8 years. The federal programs controlling NO_x emissions from selected sources are discussed in the reasonable progress and four-factor analyses.

NO_x emissions have continued to decrease gradually over the first implementation period (2007 - 2018). Although NO_x controls were in place by 2009 when CAIR became effective, the most significant NO_x emission reductions took place between 2010 and 2012 when the U.S. EPA strengthened the federal NO_x standards, establishing a new one-hour primary standard. This resulted in better visibility improvement than anticipated. NO_x emissions leveled out between 2012 and 2014; however, the most significant reductions were realized between 2014 and 2017, as previously mentioned, as a result of CSAPR being upheld in 2014. Phase 2 budget reduction took effect in 2015 under CSAPR. Actual NO_x emissions reported from the point source category decreased significantly over this 3-year timeframe with a less dramatic (compared to SO₂) but significant decrease of 33% reduction in emissions and more than 65% reduction over the entire 13-year evaluation period. NO_x emissions continued to decrease after 2017 for the first implementation period (2007 - 2018) and have yet to plateau.

Additional reductions are expected as a result of federal regulations to be implemented over the course of the next few years (such as the revised CSAPR Update), which will result in an even greater improvement in visibility than anticipated by 2028.

26.2 Impact of Visibility Improvement on Reasonable Progress Goals

Results for all Class I areas analyzed show 2014-2018 baseline monitored values, as determined through the IMPROVE monitoring data, are nearly equal and in some cases, lower than the modeled results from the base-year 2011 and base-year 2016 modeling. This emphasizes the emission reductions that have occurred in Indiana and throughout the country have realized monitored visibility benefits and the reasonable progress goals are well ahead of future projections of visibility at the Class I areas for 2028. PSAT results have shown that Indiana utilities have small visibility impacts on surrounding Class I areas. These visibility impacts have been shown through monitoring and modeling to continue to decrease and continued emissions reductions will help improve visibility impacts even more in the future. The steady decline of visibility impacts at the Class I areas from anthropogenic emissions from all emission sources over the past decade or more is

significant. This indicates that Indiana, as well as all other states, are taking the necessary steps to remain ahead of schedule in attaining natural visibility conditions at all Class I areas by 2064.

The CSAPR Update Rule, effective June 29, 2021, revises state emission budgets that reflect additional emission reductions from EGUs beginning with the 2021 ozone season to address projected 2021 emissions found to contribute at or above a threshold of 1% of the NAAQS (0.75 ppb) to the identified nonattainment and/or maintenance problems in downwind states. The rule reduces the budget for the 2021 NO_x Ozone Season to 13,051 tons with further reduction to 9,564 tons starting with the ozone season in 2024. It will be necessary to operate the NO_x reducing control devices already installed in order for EGUs to meet the state budget.

As can be seen, emission reductions, monitoring data and modeling results clearly demonstrates improved visibility, especially in the eastern half of the county. Monitoring data indicated stark reductions in impaired visibility values, which are well ahead of the uniform rate of progress for each of the Class I areas. The most current source apportionment modeling conducted by LADCO indicates Indiana's overall visibility impacts are declining. Anticipated further retirements of EGUs in the state will only continue to lower emissions and the state's visibility impacts on surrounding Class I areas.

IDEM is evaluating other emission sectors for this second implementation period to determine their visibility impacts on Class I areas. IDEM will conduct a review of all its emission sources, with focus on the EGU sector, for its January 31, 2025 progress report: pursuant to 40 CFR 51.308(g). IDEM will evaluate EGUs for the third implementation period of the RH rule, as necessary, to be submitted in 2028. As a result, IDEM is not requiring 4-factor analyses from its EGUs nor will it conduct a 4-factor analysis on this emission sector for this second implementation period.

27.0 INDIANA'S LONG-TERM STRATEGY FOR REGIONAL HAZE

27.1 Long Term Strategy Requirements

40 CFR 51.308(d)(3) requires Indiana to include in its SIP a long-term strategy that addresses RH visibility impairment for each Class I area which may be affected by emissions from Indiana sources. The LTS must include enforceable emissions limitations, compliance schedules and other measures necessary to achieve the reasonable progress goals established by the states or tribes where the Class I areas are located and include consultation with the states with Class I areas impacted by Indiana emissions. The LTS must be based on factors such as ongoing air pollution programs, construction activity impact mitigation measures, smoke management techniques for agricultural and forestry management purposes, source retirement and replacement schedules, and emission limitations and schedules for compliance to achieve Indiana's reasonable progress goals. This section describes how Indiana plans to meet its long-term strategy obligations.

27.2 Long Term Strategy

Indiana does not have any Class I areas; however, emissions from Indiana sources were determined to impact Class I areas in other states. Indiana's consultation with other states and tribes, Federal Land Managers, and RPO's by participation in the LADCO Regional Haze Workgroup calls and other RPO discussions to develop technical information necessary for development of coordinated strategies is explained in detail in Section 3. LTS development considered the impacts of Indiana's emissions on Class I areas outside of Indiana. With the emission inventory and modeling used to develop RPGs described in detail in Sections 4.0, 5.0, and 6.0 and the results of Class I area analyses described in detail in Sections 22, 23, and 24, Indiana has clearly demonstrated significant emission reductions throughout the state and its contributions to visibility impacts on Class I areas throughout the eastern half of the country is diminishing every year.

The reasonable progress analysis conducted for Indiana's EGU sources and the four-factor analyses conducted for the non-EGU sources that met IDEM's four-factor analysis selection criteria as required by the RH Rule is described in Sections 8-19, with a weight of evidence demonstration conducted to support Indiana's determination of what control measures determined to be necessary to meet Indiana's RPGs described in Section 26. As shown in Graph 26.2, Indiana's EGUs have made considerable progress toward reducing SO₂ and NO_x emissions as a result of advanced control devices installed to comply with the requirements of CSAPR and in anticipation of other federal programs aimed at reducing SO₂ emissions from fossil fuel fired EGUs to be phased in or implemented over the course of the next few years. In addition, coal-fired EGUs have less overall generating capacity due to shutdowns, and there is less pollution from coal-fired EGUs due to the conversion of existing units to natural gas and replacement of existing units with new natural gas combined cycle units.

Since EGUs control programs to reduce SO₂ and NO_x emissions were determined to be most effective in reducing visibility impacts, significant reductions were expected and have been achieved. Other source categories have contributed to emission reductions achieved throughout the state, as well. Control measures to be phased in or implemented over the course of the next few years that were not included in the modeling will result in even greater reductions in future SO₂ and NO_x emissions reductions. For example, the revised CSAPR Update Rule and other regulations focused on reducing SO₂ and NO_x emissions from fossil fuel fired EGUs and other large sources impacting visibility at Class I areas outside Indiana will allow Indiana to continue to show improvement. The control strategies that a company with affected sources use to comply with these federal programs will provide for sufficient SO₂ and NO_x emission reductions to not only meet but exceed the 2028 visibility improvement goals for Indiana as shown in the regional haze modeling results for Indiana.

27.3 Future Activities

As explained above, at this time, reductions in Indiana emissions from the BART rule and other programs are sufficient to meet the reasonable progress goals in other states.

However, to continue to assist those states in meeting their reasonable progress goals and to minimize its contribution to those states, Indiana commits to the following actions:

- 1) Effectively enforce the existing control measures with anticipated emissions reductions from implementation of revised CSAPR update rule.
- 2) Work with U.S. EPA and other states and regional planning organizations to address multi-pollutant air quality problems in the eastern and northeastern U.S.
- 3) Continue consultation with states with Class I areas to monitor their progress in meeting their reasonable progress goals and develop coordinated strategies, as and when needed, to mitigate visibility impacts in those areas.

28.0 STATE IMPLEMENTATION PLAN AND ADEQUACY OF THE EXISTING PLAN

28.1 State Implementation Plan Revisions

The federal rule at 40 CFR 51.308(f) requires Indiana to revise its regional haze implementation plan and submit a plan revision to U.S. EPA by July 31, 2028, and every ten years thereafter. In accordance with the requirements listed in 40 CFR 51.308(f) of the federal rule for regional haze, Indiana commits to doing this. In addition, 40 CFR 51.308(g) requires periodic reports evaluating progress towards the reasonable progress goals established for each mandatory Class I area. In accordance with the requirements listed in 40 CFR 51.308(g) of the federal rule for regional haze, Indiana commits to submitting a report on reasonable progress to U.S. EPA every five years following the initial submittal of the SIP. The report will be in the form of a SIP revision. The reasonable progress report will evaluate the progress made towards the reasonable progress goal for each mandatory Class I area which may be affected by emissions from Indiana sources. All requirements listed in 40 CFR 51.308(g) shall be addressed in the SIP revision for reasonable progress.

28.2 Determination of the Adequacy of the Existing Plan

Depending on the findings of the next five-year progress report, Indiana commits to taking one of the actions listed in 40 CFR 51.308(h), “Determination of the adequacy of existing implementation plan”. The findings of the five-year progress report will determine which action is appropriate and necessary. The actions in 40 CFR 51.308(h) include the following:

- 1) If the state determines that the existing implementation plan requires no further substantive revision at this time in order to achieve established goals for visibility improvement and emissions reductions, the state must provide to the Administrator

a negative declaration that further revision of the existing implementation plan is not needed at this time.

- 2) If the state determines that the implementation plan is or may be inadequate to ensure reasonable progress due to emissions from sources in another state which participated in a regional planning process, the state must provide notification to the Administrator and to the other state(s) which participated in the regional planning process with the states. The state must also collaborate with the other state(s) through the regional planning process for the purpose of developing additional strategies to address the plan's deficiencies.
- 3) Where the state determines that the implementation plan is or may be inadequate to ensure reasonable progress due to emissions from sources in another country, the state shall provide notification, along with available information, to the Administrator.
- 4) Where the state determines that the implementation plan is or may be inadequate to ensure reasonable progress due to emissions from sources within the state, the state shall revise its implementation plan to address the plan's deficiencies within one year.

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APPENDICES

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