

FINAL

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**

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October 27, 2015
Project Number: 6123150194

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List of Acronyms

AFGD	Advanced Flue Gas Desulfurization
APCD	Air Pollution Control Division
BART	Best Available Retrofit Technology
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CaSO ₃	Calcium sulfite
CaSO ₄	Calcium sulfate
CO	Carbon Monoxide
CO ₂	Carbon Dioxide
CPI	Consumer Price Index
DEP	Department of Environmental Protection
DEQ	Department of Environmental Quality
DNR	Department of Natural Resources
DSI	Dry Sorbent Injection
EIA	Energy Information Administration
EPA	Environmental Protection Agency
FGD	Flue Gas Desulfurization
FGR	Flue Gas Recirculation
ICI	Industrial, Commercial, Institutional
HEIS	High Energy Ignition Systems
LADCO	Lake Michigan Air Directors Consortium
LNB	Low NO _x Burners
MACT	Most Achievable Control Technology
MARAMA	Mid-Atlantic Regional Air Management Association
N ₂	Nitrogen gas
NCASI	National Council for Air and Stream Improvement
NESCAUM	Northeast States for Coordinated Air Use Management
NESHAP	National Emission Standards for Hazardous Air Pollutants
NH ₃	Ammonia
NO _x	Nitrogen Oxides
NSCR	Non-Selective Catalytic Reduction

NSPS	New Source Performance Standards
OFA	Over-Fired Air
PM	Particulate Matter
RICE	Reciprocating Internal Combustion Engine
RSCR.....	Regenerative Selective Catalytic Reduction
SCR	Selective Catalytic Reduction
SD	Spray Dry
SIP	State Implementation Plan
SNCR.....	Selective Non-Catalytic Reduction
SO ₂	Sulfur Dioxide
ULNB.....	Ultra Low NO _x Burners
WRAP	Western Regional Air Partnership
VOC	Volatile Organic Compounds

1 Executive Summary

The Regional Haze regulations set forth under 40 CFR 51.308(d)(1) require States to achieve reasonable progress toward natural visibility conditions. The national visibility goal in Class I areas is defined in the CAA Section 169A(a)(1) as “the prevention of any future, and the remedying of any existing, impairment of visibility...”, and is expected to be satisfied by 2064 with a return to natural visibility conditions. States containing Class I areas must set Reasonable Progress Goals (RPGs) to define future visibility conditions that are expected (but not required) to be equal to, or better, than visibility conditions expected by the uniform rate of progress at any future year until natural conditions are achieved.

The first State Implementation Plans (SIPs) under the regional haze program were due in 2007 and focused on establishing RPGs for the planning period ending in 2018. The current effort being undertaken by LADCO with support from Amec Foster Wheeler is to complete a four factor analysis of control technologies specific to large sources of pollutants that contribute to regional haze. This effort and the results are in support of establishing RPGs for Midwestern States for the implementation period ending 2028.

Following draft guidance from EPA in establishing RPGs, States must set a baseline from which reasonable progress towards visibility improvement will be measured. The next task is to identify key pollutants affecting visibility impairment at Class I areas. LADCO has identified nitrogen oxides (NO_x) and sulfur dioxide (SO₂) as major pollutants contributing to visibility impairment in Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin.

In order to determine the key source regions and source types contributing to visibility impairment at each Class I area, LADCO member states evaluated their emission inventories to identify large individual sources and source categories of NO_x and SO₂. Based on information from the contribution assessment, LADCO selected the following source categories for analysis in this project:

- Industrial, commercial, and institutional boilers at paper mills and sugar beet manufacturing facilities;
- Cement plants
- Lime plants
- Pipeline transportation of natural gas

In addition to the source category analysis, LADCO States and EPA identified 10 specific facilities from these source categories for review. The 10 facilities were selected based on emissions of NO_x and SO₂, and Q/d analysis to determine their impact on Class I areas. We examined the current control status and planned controls for these individual facilities in this analysis.

This document presents the results of an analysis of the economic and non-air quality environmental impacts of potential control scenarios that could be implemented by LADCO States to reduce emissions from the above source categories in order to make reasonable progress toward meeting visibility improvement goals. The purpose of this analysis is to present information that can be used by States to develop policies and implementation plans to address reasonable progress goals. Control technologies to achieve reasonable progress goals are evaluated with respect to four factors listed in the Clean Air Act (Section 169A):

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

The “four factor” analysis was applied to control options identified for each of the selected source categories. Kilns at cement and lime plants were analyzed together due to the similarity of the two source categories.

The table below presents a summary of the four factor analysis for the source categories analyzed. Detailed information on control technologies assessed in this effort is presented in the main body of this document.

Table 1-1 Summary of Results from the Four Factor Analysis

Source Category	Regional Haze Pollutant Analyzed	Average Cost in 2015 dollars (per ton of pollutant reduction)	Compliance Timeframe	Energy and Non-Air Quality Environmental Impacts	Remaining Useful Life
ICI Boilers at Pulp and Paper Mills and Sugar Beet Manufacturing Facilities	NOx	\$450-\$17,000	2-5 years following SIP submittal	Efficiency loss, increased fuel consumption, solid waste disposal, reagent storage, and ammonia slip	10-30 years
	SO ₂	\$400-\$4,700	2-5 years following SIP submittal	Solid waste disposal, wastewater issues, and efficiency loss	10-30 years
Kilns at Lime and Cement Plants	NOx	\$200-\$21,100	2-5 years following SIP submittal	Efficiency loss, increased fuel consumption, solid waste disposal, reagent storage, and ammonia slip.	10-30 years
	SO ₂	\$1,500-\$88,800	2-5 years following SIP submittal	Solid waste disposal, wastewater issues, and efficiency loss	10-30 years
Pipeline Transportation of Natural Gas	NOx	\$220-\$9,200	2-5 years following SIP submittal	Efficiency loss and increased fuel consumption	15 years

2 Introduction

2.1 Background

The Regional Haze regulations set forth under 40 CFR 51.308(d)(1) require States to achieve reasonable progress toward natural visibility conditions. The national visibility goal in Class I areas is defined in the CAA Section 169A(a)(1) as “the prevention of any future, and the remedying of any existing, impairment of visibility...”, and is expected to be satisfied by 2064 with a return to natural visibility conditions. States containing Class I areas must set Reasonable Progress Goals (RPGs) to define future visibility conditions that are expected (but not required) to be equal to, or better, than visibility conditions expected by the uniform rate of progress at any future year until natural conditions are achieved.

The first State Implementation Plans (SIPs) under the regional haze program were due in 2007 and focused on establishing RPGs for the planning period ending in 2018. The current effort being undertaken by LADCO with support from Amec Foster Wheeler is to complete a four factor analysis of control technologies specific to large sources of pollutants that contribute to regional haze. This effort and the results are in support of establishing RPGs for Midwestern States for the implementation period ending 2028.

Following draft guidance from EPA in establishing RPGs, States must set a baseline from which reasonable progress towards visibility improvement will be measured. The next task is to identify key pollutants affecting visibility impairment at Class I areas. LADCO has identified nitrogen oxides (NO_x) and sulfur dioxide (SO₂) as major pollutants contributing to visibility impairment in Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin.

In order to determine the key source regions and source types contributing to visibility impairment at each Class I area, LADCO member states evaluated their emission inventories to identify large individual sources and source categories of NO_x and SO₂ that contribute to visibility impairment on the 20 percent best and worst days. Based on information from the contribution assessment, LADCO selected the following source categories for analysis in this project:

- Industrial, commercial, and institutional boilers at paper mills and sugar beet manufacturing facilities;
- Cement plants
- Lime plants
- Pipeline transportation of natural gas

In addition to the planned reductions that will be included as part of the State SIPs for regional haze, federal programs will also have significant benefits in reducing regional haze by 2028 and beyond. A list of EPA’s national and regional rules as well as voluntary programs that will assist in the reduction of fine particle pollution are as follows:

- Clean Air Interstate Rule (CAIR)
- Clean Air Visibility Rule
- The Acid Rain Program
- NO_x SIP Call
- 2004 Clean Air Nonroad Diesel Rule
- 2007 Clean Diesel Trucks and Buses Rule
- Tier 2 Vehicle Emission Standards and Gasoline Sulfur Program
- Emission standards for other engines (highway and non-highway use)
- National Clean Diesel Campaign
- The Great American Woodstove Changeout

More information and links to the programs listed above can be found on the following website: <http://www3.epa.gov/pm/reducing.html>.

2.2 Determination Of Emission Source Categories And Individual Sources Most Responsible For Regional Haze In LADCO Class I Areas

Particles in the PM_{2.5} size range are directly responsible for visibility reduction, however, in many cases these particles are not directly emitted as particulate matter, but instead are formed through the reaction of other pollutants such as NO_x and SO₂. PM_{2.5} formed through reaction is known as secondary PM_{2.5}. Source apportionment and other analyses documented in LADCO's emissions inventory assessment and contribution assessment indicated that a number of source categories have impacts on visibility at LADCO's Class I areas resulting from emissions of these PM_{2.5} precursor pollutants and the resulting formation of haze.

2.2.1 Approach to Demonstrating Reasonable Progress

Based on the contribution assessment conducted by LADCO States, the following source categories were selected for analysis in this project:

- Industrial, commercial, and institutional boilers at paper mills and sugar beet manufacturing facilities;
- Cement plants
- Lime plants
- Pipeline transportation of natural gas

This document presents the results of an analysis of the economic and non-air quality environmental impacts of potential control scenarios that could be implemented by LADCO States to demonstrate reasonable progress toward meeting visibility improvement goals. The purpose of this analysis is to present information that can be used by States to develop policies and implementation plans to address reasonable progress goals. Control technologies to achieve reasonable progress goals are evaluated with respect to four factors listed in the Clean Air Act (Section 169A):

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

The "four factor" analysis was applied to control options identified for each of the selected source categories. Category analyses are presented for industrial, commercial, and institutional boilers at paper mills and sugar beet manufacturing facilities; kilns at cement and lime plants; and pipeline transportation of natural gas. Kilns at cement and lime plants were analyzed together due to the similarity of the two source categories. Only NO_x emissions were considered from pipeline transportation of natural gas.

Additionally, we have assembled current and planned controls for 10 specific sources selected by the LADCO states and based on information from State agencies and EPA. The purpose of selecting these sources is to find out whether the sources that have the greatest impacts on Class I areas in or near the LADCO six-state region are already controlled or will be controlled by 2028.

REFERENCES

EPA. Information accessed on the web September 15, 2015.
<http://www3.epa.gov/pm/reducing.html>

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3 Source Category Analysis for Industrial, Commercial, and Institutional Boilers at Pulp and Paper Mills and Sugar Beet Manufacturing Facilities

3.1 Source Category Description

The emission inventory and contribution assessment performed by LADCO demonstrated that NO_x and SO₂ emissions were key contributors to visibility impairment in Class I areas in the LADCO States. Boilers used to produce steam for electricity generation as well as boiler units used in industrial, commercial, and institutional settings are among the most significant contributors of NO_x and SO₂ in any inventory. Emissions of these pollutants is highly dependent on many emission unit-specific factors including type of fuel and in-place emissions controls. Also, emissions of these pollutants from boilers used for electricity generation have been the focus of many prior control initiatives. For the purpose of the current four-factor analysis, LADCO selected boilers at pulp and paper mills and sugar beet manufacturing facilities for review. Boilers at these facilities are typically among the largest of non-EGU boilers and therefore have the highest emissions potential.

Pulp and paper and sugar beet manufacturing facilities have high steam demands and typically have access to a large variety of industry-specific fuels (e.g. wood waste, black liquor solids, other biofuels). As a result, these facilities employ large boilers configured to burn multiple fuels including coal, natural gas, wood waste, fuel oils, biogas, black liquor solids, etc. Due to the size of these boilers and their corresponding emissions potential, most of the units are fitted with controls for one or more of NO_x, SO₂ and particulate matter. Many of these units are also subject to New Source Review (NSR) or Prevention of Significant Deterioration (PSD) limits for these pollutants that vary depending on when the boiler was last subject to PSD review due to a modification.

The use of a wide variety of fuels is an important characteristic of the Industrial, Commercial, Institutional (ICI) boiler category. While many boilers are capable of co-firing liquid or gaseous fuels in conjunction with solid fuels, boilers are usually designed for optimum combustion of a single specific fuel. Changes to the fuel type may, therefore, reduce the capacity, duty cycle, or efficiency of the boiler.

Boiler design also plays a role in the uncontrolled emission rate. Most ICI boilers are of three basic designs: water tube, fire tube, or cast iron. The fuel-firing configuration is a second major identifier of boiler design for solid fuels. Stoker boilers are the oldest technology and are still widely used for solid-fueled boilers. Pulverized coal boilers succeeded stokers as a more efficient method of burning coal and are used in larger boiler designs. Circulating fluidized bed (CFB) boilers are the most recent type of boiler for solid fuel combustion and are becoming more commonplace. CFB boilers are capable of burning a variety of fuels, and are more efficient and less polluting than stoker or pulverized coal boilers.

3.2 Clean Air Act Regulations Controlling ICI Boilers

Emissions from ICI boilers are currently governed by multiple State and federal regulations under Titles I, III, and IV of the Clean Air Act. Each of these regulatory programs is discussed in the following paragraphs.

Title I regulates criteria pollutants by requiring local governments to adopt State Implementation Plans (SIPs) that set forth their strategy for achieving reductions in the particular criteria pollutant(s) for which they are out of attainment. The SIP requirements includes Reasonably Available Control Technology (RACT) requirements, but more stringent requirements may be imposed depending on the locale's degree of non-attainment with ambient air standards.

Title I also imposes New Source Performance Standards (NSPS) on certain specified categories of new and modified large stationary sources. In 1986, EPA codified the NSPS for industrial boilers (40 CFR part 60, subparts Db and Dc) and revised portions of them in 1998 to reflect improvements in control methods for the reduction of NO_x emissions. Subpart Db applies to fossil fuel-fired ICI units greater than 100 MMBTU per hour that were constructed or modified after June 19, 1984. Subpart Dc applies to fossil fuel-fired ICI units from 10 to 100 MMBTU per hour that were constructed or modified after June 9, 1989.

In addition, Title I subjects new and modified large stationary sources that increase their emissions to permitting requirements that impose control technologies of varying levels of stringency. NSR prescribes control technologies for new plants and for plant modifications that result in a significant increase in emissions, subjecting them to Best Available Control Technology (BACT) in attainment areas and to the Lowest Achievable Emission Rate (LAER) in non attainment areas. Control strategies that constitute BACT and LAER evolve over time and are reviewed on a case by case basis in State permitting proceedings.

On September 13, 2004, EPA published a final rule under Title III of the CAA to substantially reduce emissions of toxic air pollutants from ICI boilers. These Maximum Achievable Control Technology (MACT) standards apply to ICI boilers located at major sources of hazardous air pollutants (HAPs). There are many options for complying with the MACT standards, ranging from continued use of existing control systems to fuel switching to the installation of a fabric filter and wet scrubber technologies. Thus, the control technologies used to reduce the level of HAP emitted from affected sources are also expected to reduce emissions of PM, and to a lesser extent, SO₂ emissions.

On January 31, 2013, EPA published a final version of the Major Source Boiler MACT. Compliance with the Boiler MACT is required by January 31, 2016 with the opportunity to apply for up to one year compliance extension to January 31, 2017 for major sources of hazardous air pollutants. The focus of the Boiler MACT is to reduce emissions of hazardous air pollutants (HAPs). Emissions of HAPs from boilers is affected by fuel type

and combustion conditions and is tied to emissions of particulate matter and carbon monoxide. Emissions controls for boilers subject to the Boiler MACT may impact emissions of NO_x and SO₂.

Title IV of the CAA addresses acid rain by focusing primarily on power plant emissions of SO₂. Title IV includes an Opt-in Program that allows sources not required to participate in the Acid Rain Program the opportunity to enter the program on a voluntary basis and receive their own acid rain allowances. The Opt-in Program offers sources such as ICI boilers a financial incentive to voluntarily reduce its SO₂ emissions. By reducing emissions below allowance allocation, an opt-in source will have unused allowances, which it can sell in the SO₂ allowance market.

The regulation of ICI boilers by various CAA programs has resulted in a variety of unit level emission limits resulting from SIP, NSPS, NSR, or MACT requirements. Overlaid on these unit level requirements are system-wide allowances of the NO_x SIP call and the Acid Rain SO₂ opt-in program. Thus, the specific emission limits and control requirements for a given ICI boiler vary and depend on boiler age, size, and geographic location.

3.3 NO_x from Industrial, Commercial, and Institutional Boilers at Pulp and Paper Mills and Sugar Beet Manufacturing Facilities

3.3.1 NO_x Emissions and Control Options

Nitrogen oxides are a by-product of combustion. Nitrogen is inherently contained in fuels and in the air and does not react at low temperatures. During combustion, the high temperatures cause the nitrogen and oxygen in the air to react and form NO_x. The amount of NO_x formed is dependent on many factors including the type of fuel combusted, temperature, and residence time of the air. NO_x formation can be classified into the following four categories: thermal NO_x, fuel NO_x, feed NO_x, and prompt NO_x. Thermal NO_x is formed from nitrogen and oxygen in the air as a result of high temperature. Thermal NO_x formation has a positive correlation with temperature. Fuel NO_x is the result of nitrogen contained in organic fuels releasing and reacting with oxygen. Some fuels, such as natural gas, typically have no bound nitrogen, however, others such as coal or oil can contain high amounts. Feed NO_x is caused by reaction of the nitrogen in feed materials in a process, such as the constituents of cement, in a high temperature environment. Feed NO_x is not usually a concern for boilers. Prompt NO_x is formed as atmospheric nitrogen, atmospheric oxygen, and hydrocarbons from the fuel rapidly react. It is a minor contributor to overall NO_x formation.

Due to the multiple factors affecting NO_x formation from combustion, there are different methods of reducing or controlling NO_x emissions. The potential control types analyzed in this report can be categorized into the following two categories: combustion modifications and post-combustion NO_x controls. Combustion modifications are changes to one or more controllable variables in the combustion process itself, such as temperature and combustion air 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 release 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 boiler, fuel(s) used, heat input capacity, and mode of operation.

A summary of the potential NO_x control options is provided in Table 3-1.

Table 3-1 Potential NOx Control Options for Industrial, Commercial, and Institutional Boilers at Pulp and Paper Mills and Sugar Beet Manufacturing Facilities

Technology	Description	Applicability	Performance
Boiler Tuning/Optimization ⁴	Adjust air to fuel ratio	Potential control measure for all boilers	5-15% reduction in NOx
LNB ^{2,5}	Low NOx burners	Potential control measure for all boilers; dependent on fuels burned, boiler use, and boiler configuration	40-50% reduction in NOx
ULNB ^{1,2}	Ultra low NOx burners	Potential control measure for all boilers; dependent on fuels burned, boiler use, and boiler configuration	45-85% reduction in NOx
LNB + FGR ^{1,2}	Low NOx burners and flue gas recirculation	Potential control measure for all boilers; dependent on fuels burned, boiler use, and boiler configuration	50-70% reduction in NOx
LNB + OFA ^{2,5}	Low NOx burners and over-fired air	Potential control measure for all boilers; dependent on fuels burned, boiler use, and boiler configuration	40-60% reduction in NOx
SCR ^{1,2}	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 boilers; dependent on flue gas temperature and boiler configuration	70-90% reduction in NOx
SNCR ^{2,3}	A reducing agent such as ammonia is introduced into the flue gas stream to form nitrogen gas.	Potential control measure for all boilers; dependent on flue gas temperature and boiler configuration	10-70% reduction in NOx
RSCR ^{2,3,4}	A reducing agent such as ammonia is introduced into the flue gas stream to form nitrogen gas in the presence of a catalyst and heat exchangers.	Potential control measure for all boilers; dependent on boiler configuration	60-75% reduction in NOx

Table references:

1. *Midwest Regional Planning Organization Boiler BART Engineering Analysis*. LADCO. March 2005.
2. *Applicability and Feasibility of NOx, SO2, and PM Emissions Control Technologies for ICI Boilers*. NESCAUM. November 2008.
3. *EPA Cost Estimates for NOx Controls on Pulp and Paper Boilers are too Low by 100->300%*. NESCAUM.
4. *BART Determination – Georgia Pacific Broadway Mill, Green Bay Wisconsin*. Wisconsin DNR. July 2011.
5. *Assessment of Control Options for BART-Eligible Sources*. NESCAUM and MANE-VU. March 2005.

3.3.1.1 Combustion Modification

Boiler Tuning/Optimization

One method of combustion modification to control NO_x from boilers is “tuning,” also known as optimization. The air to fuel ratio for combustion is analyzed and adjusted to lower NO_x emissions. This may also result in more efficient combustion and better boiler performance. The reduction efficiency possible through boiler tuning is dependent on how “de-tuned” the boiler was prior to optimization, but 5 to 15 percent reduction of NO_x can be achieved.

Low/Ultra Low NO_x Burners

Low NO_x burner (LNB) technology utilizes alternate burner designs to reduce the formation of NO_x. Temperature, residence time, and oxygen levels can be altered from traditional burner designs. LNBs utilize staged combustion, where fuel is introduced to an oxygen-rich, low temperature zone, and any uncombusted fuel is burned in a lower oxygen zone. In addition, the surface area of LNBs is increased to lower flame temperature and reduce thermal NO_x production. Ultra Low NO_x Burners (ULNB) often use similar designs and can decrease NO_x emissions to up to 85 percent, and LNBs can decrease NO_x emissions on average by 40 to 50 percent (LADCO, 2005). LNBs are often combined with other combustion modification controls like flue gas recirculation and over-fired air.

LNBs can result in significantly lower efficiencies, depending on the boiler and burners chosen. Suitability of LNBs must be carefully analyzed for each individual boiler.

Flue Gas Recirculation

Flue gas recirculation (FGR) returns a portion of post-combustion stack gas to the burners. This lowers the oxygen content of the combustion air and decreases the flame temperature, thus less thermal NO_x is formed. FGR is often combined with LNBs and can reduce emissions by 50 to 72 percent for coal and oil fired boilers (NESCAUM, 2008). Retrofitting an FGR system to a boiler is sometimes challenging or infeasible, depending on the unit.

Over-fired Air

Over-fired air (OFA) is a form of staged combustion that works by directing a portion of the combustion air from the last burners to ports downstream. This creates a more fuel-rich environment near the burners. Less thermal NO_x is formed due to lowered temperatures at the combustion zones and less oxygen near the burners. OFA can be combined with LNBs to reduce NO_x emissions by 40 to 60 percent.

3.3.1.2 Post-Combustion NOx Controls

Selective Non-Catalytic Reduction

Selective Non-Catalytic Reduction (SNCR) removes NOx by injecting urea or another reducing agent into the flue gas. The reagent reacts with NOx to form nitrogen gas (N₂) and water. Temperatures between 1,700 and 2,000 °F are optimal for the reaction. SNCR systems can reduce NOx emissions by 30 to 60 percent. The use of LNBS with an SNCR system can increase the reduction efficiency to 50 to 90 percent of NOx (LADCO, 2005).

Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) is similar to SNCR in that it removes NOx by injecting a reducing agent (typically ammonia) into the flue gas; however, SCR utilizes a catalyst. The catalyst lowers the activation energy needed for the reaction of NOx and ammonia to form nitrogen gas and water. As a result, SCRs are appropriate for boilers with lower flue gas temperatures. Depending on the catalyst used, temperatures of 470 to 1000 °F are required for proper reduction of NOx (LADCO, 2005). Below this range, unreacted ammonia is released to the atmosphere, and above this range, ammonia oxidizes to form additional NOx. A properly maintained SCR system can reduce NOx emissions by 70 to 90 percent, more than an SNCR system, but have lower operating costs and higher capital costs (NESCAUM, 2008). A boiler operator may also install ULNB with an SCR system to decrease NOx emissions by up to 95 percent (LADCO, 2005).

Regenerative Selective Catalytic Reduction

Regenerative Selective Catalytic Reduction (RSCR™) is an alternative to SCR for smaller boilers or boilers with particulate control equipment upstream of the control device. An SCR system requires a minimum flue gas temperature of 470 °F which may not be possible for some boiler systems. An RSCR system utilizes ceramic heat exchangers and a burner to bring the flue gas up to a suitable temperature for the reaction of NOx and ammonia (or similar reducing agent) to occur. NOx reduction efficiencies of 60 to 75 percent of can be achieved.

3.3.2 Four Factor Analysis of Potential NOx Control Scenarios for Industrial, Commercial, and Institutional Boilers at Pulp and Paper Mills and Sugar Beet Manufacturing Facilities

A four factor analysis approach has been utilized to analyze the potential control options presented in Table 3-1.

3.3.2.1 Cost of Compliance

Information on cost effectiveness of retrofitting controls onto boilers 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 size of the individual boiler as well as specific capital costs associated with the design.

Combustion modifications are generally low cost in comparison to post-combustion controls. Costs from boiler tuning include engineering and contractor costs to measure the oxygen and carbon monoxide concentrations in the flue gas and adjust the air to fuel mixture appropriately. LNBS and ULNBS are generally cost effective but the impacts on boiler efficiency must be considered. Associated costs are from engineering, the burners and related equipment, and labor costs for installation. Costs from retrofitting FGR or OFA can vary greatly depending on the boiler design. Engineering, equipment such as piping and fans, and labor costs make up the bulk of the costs. If extensive changes to the boiler are required to retrofit FGR or OFA, the costs can easily exceed cost effective levels.

Post-combustion NOx controls are generally much more cost intensive than combustion modifications, but can provide significantly higher reductions in NOx. The applicability of each type of post-combustion control should be carefully assessed for each unit. Considerations include space constraints, flue gas temperature, if fly ash is sold (the reducing agent may contaminate fly ash depending on the system chosen), and load swings of the boiler. For boilers with high temperature flue gas streams, an SNCR system may be considered. No reactor is required for SNCR as the urea or other reducing agent can be injected directly into the flue. This reduces capital costs for the system; however, operating costs are higher due to lower efficiency and more reagent use. For boilers with flue gas stream temperatures lower than those required for SNCR system, SCR and RSCR systems may be viable. They have high capital costs as a result of the dedicated reactor and catalyst required for each system; however, reagent costs are lower than for an SNCR system and NOx reduction efficiency is greatly increased. (NESCAUM, 2008).

Table 3-2 summarizes the cost effectiveness and factors affecting 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 increased or 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.

Table 3-2 Cost Effectiveness for NOx Control Options for ICI Boilers at Pulp and Paper Mills and Sugar Beet Manufacturing Facilities

Control Option	Specific Design Parameters Identified	Cost Effectiveness (2015 \$/ton)^a	Factors Affecting Cost	Potential Applicability to Specific Facilities (Unit ID)
Boiler Tuning/Optimization ⁴	None	Low	Engineering and contractor costs	All pulp and paper mill and beet manufacturing facility boilers
LNB ^{2,5}	None	\$450-\$3,700	Equipment, installation, and engineering	03-01, 03-02, 06-01, 06-02, 08-01, 08-02, 09-01, 09-02, 10-02, 10-03
ULNB ^{1,2}	None	\$650-\$2,200	Equipment, installation, and engineering	03-01, 03-02, 06-01, 06-02, 08-01, 08-02, 09-01, 09-02, 10-02, 10-03
SCR ^{1,2}	Ammonia injection system	\$2,600-\$17,000	Equipment, installation, engineering, energy use, waste removal, reduction agent, and catalyst	All pulp and paper mill and beet manufacturing facility boilers; dependent on temperatures
SNCR ^{2,3}	Urea injection system	\$1,500-\$4,400	Equipment, installation, engineering, energy use, waste removal, and reduction agent	All pulp and paper mill and beet manufacturing facility boilers; dependent on temperatures
RSCR ^{2,3,4}	Ammonia injection system	\$1,800-\$5,300	Equipment, installation, engineering, energy use, waste removal, reduction agent, and catalyst	All pulp and paper mill and beet manufacturing facility boilers; dependent on temperatures

Table 3-2 Cost Effectiveness for NOx Control Options for ICI Boilers at Pulp and Paper Mills and Sugar Beet Manufacturing Facilities

Control Option	Specific Design Parameters Identified	Cost Effectiveness (2015 \$/ton)^a	Factors Affecting Cost	Potential Applicability to Specific Facilities (Unit ID)
LNB + FGR ^{1,2}	None	\$1,200-\$4,300	Equipment, installation, construction and engineering	03-01, 03-02, 06-01, 06-02, 08-01, 08-02, 09-01, 09-02, 10-02, 10-03
LNB + OFA ^{2,5}	None	\$700-\$3,700	Equipment, installation, construction and engineering	03-01, 03-02, 06-01, 06-02, 08-01, 08-02, 09-01, 09-02, 10-02, 10-03
LNB + SNCR ¹	Urea injection system	\$1,700-\$4,500	Equipment, installation, engineering, energy use, waste removal, reduction agent, and catalyst	03-01, 03-02, 06-01, 06-02, 08-01, 08-02, 09-01, 09-02, 10-02, 10-03
ULNB + SCR ¹	Ammonia injection system	\$2,900-\$5,100	Equipment, installation, engineering, energy use, waste removal, reduction agent, and catalyst	03-01, 03-02, 06-01, 06-02, 08-01, 08-02, 09-01, 09-02, 10-02, 10-03

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

Table references:

1. *Midwest Regional Planning Organization Boiler BART Engineering Analysis*. LADCO. March 2005.
2. *Applicability and Feasibility of NOx, SO₂, and PM Emissions Control Technologies for ICI Boilers*. NESCAUM. November 2008.
3. *EPA Cost Estimates for NOx Controls on Pulp and Paper Boilers are too Low by 100->300%*. NESCAUM.
4. *BART Determination – Georgia Pacific Broadway Mill, Green Bay Wisconsin*. Wisconsin DNR. July 2011.
5. *Assessment of Control Options for BART-Eligible Sources*. NESCAUM and MANE-VU. March 2005.

3.3.2.2 Time Necessary for 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 NO_x controls require significant time for engineering, construction, and facility preparedness. Two to five years after SIP approval would typically be appropriate, depending on the size of the unit and control options selected. Substantially less time would be required for boiler optimization and tuning which can be implemented within a few months to a year.

3.3.2.3 Energy and Non-Air Impacts

Combustion modification and post-combustion NO_x 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. Some control technologies may result in nuisances in the form of noise pollution or odor.

Combustion modifications can have significant impacts on energy use, positively or negatively. Boiler tuning, LNB/ULNBs, OFA, and FGR can reduce the efficiency of a boiler as the air to fuel ratio increases and temperature decreases. This increases fuel usage and, as a result, costs. OFA and FGR systems increase energy use in the form of fans and compressors. Facilities that sell fly ash may be affected due to the higher CO concentrations making the fly ash unsuitable for sale (NESCAUM, 2008).

Post-combustion NO_x controls may also impact energy use for boilers. SCR, SNCR, and RSCR systems reduce thermal efficiency by using thermal energy in the reaction of NO_x and reagent. Fans, compressors, injection equipment, and related processes utilize energy and increase costs. For SCR, SNCR, and RSCR systems, the reagent (usually ammonia or urea) can contaminate fly ash, making it unsalable.

3.3.2.4 Remaining Useful Life at the Source

The remaining useful life of an individual boiler can vary greatly depending on the age of the boiler, size of the unit, maintenance frequency, and other factors. Life expectancies for most industrial, commercial, and institutional boilers at pulp and paper mills and sugar beet manufacturing facilities are between 10 and 30 years or more.

REFERENCES

The Lake Michigan Air Directors Consortium (LADCO). *Midwest Regional Planning Organization Boiler Best Available Retrofit Technology Engineering Analysis*. March 30, 2005.

Northeast States for Coordinated Air Use Management (NESCAUM). *Applicability and Feasibility of NO_x, SO₂, and PM Emissions Control Technologies for Industrial, Commercial, and Institutional (ICI) Boilers*. November 2008.

NESCAUM. *EPA Cost Estimates for NO_x Controls on Pulp and Paper Boilers are too Low by 100->300%*.

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U.S. EPA. 2015. *EPA Air Pollution Control Cost Manual*. "Chapter 2 – Selective Catalytic Reduction." Draft. June 2015.

Wisconsin DNR. BART Determination – Georgia Pacific Broadway Mill, Green Bay Wisconsin. July 2011.

3.4 SO₂ from Industrial, Commercial, and Institutional Boilers at Pulp and Paper Mills and Sugar Beet Manufacturing Facilities

3.4.1 SO₂ Emissions and Control Options

Sulfur dioxide is formed in boilers when the sulfur in fossil fuels oxidizes. Unlike NO_x, the only mechanism of SO₂ generation is directly related to the sulfur content of fuel – temperature has no effect. Nearly all of the sulfur contained in the fuels is converted to SO₂. As a result, the simplest way to reduce SO₂ emissions is to switch to a lower sulfur fuel. For instances where this is impractical, post-combustion SO₂ controls may be employed to remove the SO₂ already created. 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 as the costs are highly variable, and feasibility is dependent on individual boiler characteristics and functions. A description with reduction efficiencies is provided, however.

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 boilers. One such modification is conversion to fluidized bed whereby fuel is combusted in a bed of ash, limestone, and other materials. The limestone in the bed captures most of the SO₂ and reduces emissions significantly. Fluidized bed conversion has not been analyzed in this report due to the highly unit specific nature of such a conversion.

Post-combustion SO₂ controls utilize add-on control technologies to decrease the amount of formed SO₂ 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 boiler, fuel(s) used, heat input capacity, and mode of operation.

Table 5-1 Pre-combustion and post-combustion SO₂ controls are described in the next two sections. Table 3-3 summarizes appropriate SO₂ control options for ICI boilers.

Table 3-3 Potential SO₂ Control Options for Boilers at Pulp and Paper Mills and Beet Manufacturing Facilities

Technology	Description	Applicability	Performance
Conventional Dry Flue Gas Desulfurization (FGD) – Dry Sorbent Injection ¹	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 boilers; dependent on fuels burned, boiler use, and boiler configuration	35-50% reduction in SO ₂
Conventional Dry Flue Gas Desulfurization (FGD) – Spray Dryer ^{1,2}	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 boilers; dependent on fuels burned, boiler use, and boiler configuration	90-95% reduction in SO ₂
Advanced Flue Gas Desulfurization (AFGD) ²	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 boilers; dependent on fuels burned, boiler use, and boiler configuration	95-99% reduction in SO ₂
Wet Flue Gas Desulfurization (FGD) ^{1,2,3}	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 boilers; dependent on fuels burned, boiler use, and boiler configuration	90-99% reduction in SO ₂

Table references:

1. *Applicability and Feasibility of NO_x, SO₂, and PM Emissions Control Technologies for ICI Boilers*, NESCAUM, November 2008.
2. *Midwest Regional Planning Organization Boiler BART Engineering Analysis*, LADCO, March 2005.
3. *BART Determination - Georgia Pacific Broadway Mill, Green Bay Wisconsin*, Wisconsin DNR, July 2011.

3.4.1.1 Pre-Combustion SO₂ Controls

Fuel Substitution

The most direct way to control SO₂ from boilers is by changing the fuel used. The percent reduction possible depends on what fuel is currently used and what fuel will be used in the future. According to the U.S. Energy Information Administration, the most used coal types are typically between 0.8 and 5 percent sulfur by weight. Fuel oils can have 1 to 2 percent sulfur by weight for residual and less than 0.5 percent sulfur by weight for distillate, and petroleum coke has as much as 6 percent sulfur by weight (MARAMA, 2007). Tire derived fuel (TDF) contains approximately 1.6 percent sulfur by weight, similar to that of a medium-sulfur content coal (NCASI, 2010). The sulfur content of wood is very low, and pipeline natural gas has virtually zero sulfur. To change from one fuel to another, many factors must be considered on an individual unit basis. Switching fuels can be relatively simple or very complicated, depending on the capacity, burners, type of use, and other factors. Switching to a lower sulfur coal potentially results in increased transportation costs and cost of coal. Heat content of fuel also varies significantly between fuel types and subtypes. Changes to the fuel system may also result in significant costs. Another consideration is that controls for particulate may already exist on a boiler and would become unnecessary depending on the fuel switch, thus putting additional financial burden onto a single facility.

3.4.1.2 Post-Combustion SO₂ Controls

Flue Gas Desulfurization

Flue gas desulfurization (FGD) is the process of scrubbing SO₂ out of the combustion air. There are two basic processes of FGD – wet and dry. Dry FGD can be further categorized as conventional and advanced. Each of these FGD systems utilize the same basic principle to remove SO₂. An alkaline chemical such as limestone or lime reacts with SO₂ to form solid calcium sulfite (CaSO₃) and calcium sulfate (CaSO₄), which is collected. Descriptions of the different types of FGD are below.

Conventional Dry FGD

Conventional dry FGD includes dry sorbent injection (DSI) and spray dryers (SDs). In DSI, lime, calcium hydrate, limestone or soda ash is injected into the flue gas stream producing solid particles of CaSO₃ and CaSO₄. In boilers, injection can take place in the furnace, economizer, or in a low-temperature duct. The particles generated by DSI and excess reagent are removed from the gas stream using a particulate control device. SO₂ removal efficiency depends on absorbent injection location, temperature, degree of mixing, and retention time. SO₂ reduction through dry sorbent injection on boilers ranges from 35 to 50 percent (NESCAUM, 2008). In an SD system, lime slurry is sprayed onto flue gas within an absorption tower.

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 evaporation are collected with a fabric filter or ESP. SO₂ reduction by spray dryers on boilers ranges from 90 to 95 percent (LADCO, 2005).

It must be noted that flue gases at or near adiabatic saturation temperatures can cause 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 boiler exit gas temperatures are above adiabatic saturation temperatures (LADCO, 2005).

When coal is used as fuel, low to medium sulfur coals work best for conventional dry FGD because it inhibits high solids generation. Solids need to be kept under a certain threshold within the slurry to allow for atomization and to limit particulate emissions. Therefore, when higher sulfur fuels are used, wet FGD is preferred, which is described later in this section.

Advanced Flue Gas Desulfurization

Advanced flue gas desulfurization (AFGD) systems utilize 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 with absorbed SO₂ falls into the slurry reservoir below where unreacted acids are neutralized further by injected dry limestone powder. 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.

Air is injected into the slurry in the reservoir 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 located before the absorber. The gypsum created is wallboard quality gypsum which can be added in the final grinding process regulate concrete setting time. Particulate collected in the ESP consists of water evaporates and dissolved solids that can be

collected for disposal or sale. SO₂ reduction through AFGD ranges from 95 to 99.5% (LADCO, 2005).

Wet Flue Gas Desulfurization

Wet FGD systems are most commonly used on boilers to treat the flue gas. SO₂ emissions can be reduced by 90 to 99% through the use of a wet FGD system (LADCO, 2005). 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 caustic is used, liquid waste is produced and add-on waste collection equipment is minimal. When lime or limestone is used, additional steps and equipment are required to stabilize the watery calcium sulfite or calcium sulfate sludge produced. Fly ash is typically used to stabilize the calcium sulfite sludge. 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.

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.

3.4.2 Four Factor Analysis of Potential SO₂ Control Scenarios for Industrial, Commercial, and Institutional Boilers at Pulp and Paper Mills and Sugar Beet Manufacturing Facilities

A four factor analysis approach has been utilized to analyze the potential control options presented in Table 3-3.

3.4.2.1 Cost of Compliance

Information on cost effectiveness of retrofitting controls onto boilers 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 size of the individual boiler as well as specific capital costs associated with the design.

Pre-combustion (e.g., fuel substitution) and combustion modifications (i.e. conversion to fluidized bed) were not discussed in detail in this assessment due to highly variable costs determined by individual boiler 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 the least expensive and most readily available. 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 at an acceptable temperature in dry FGD, equipment like an evaporative cooler, a heat exchanger, or a heat recovery boiler will be needed. These additions will increase 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.

Table 3-4 summarizes the cost effectiveness and factors affecting cost of each control option addressed in this analysis. 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.

Table 3-4 Cost Effectiveness for SO₂ Control Options for ICI Boilers at Pulp and Paper Mills and Sugar Beet Manufacturing Facilities

Control Option	Specific Design Parameters Identified	Cost Effectiveness (2015 \$/ton) ^a	Factors Affecting Cost	Potential Applicability to Specific Facilities
Conventional Dry Flue Gas Desulfurization (FGD) – Dry Sorbent Injection ¹	Direct flue gas application, lime/calcium hydrate/limestone/soda ash injection, PM control device	\$400-\$1,200	Equipment, installation, engineering, reagent, and waste removal	All pulp and paper mill and beet manufacturing facility boilers
Conventional Dry Flue Gas Desulfurization (FGD) – Spray Dryer ^{1,2}	Absorption tower, lime slurry injection, PM control device	\$1,900-\$4,200	Equipment, installation, engineering, reagent, and waste removal	All pulp and paper mill and beet manufacturing facility boilers
Advanced Flue Gas Desulfurization (FGD) ²	Lime slurry injection, PM control device	\$1,500-\$3,700	Equipment, installation, engineering, reagent, energy use, waste removal, and byproduct resale	All pulp and paper mill and beet manufacturing facility boilers
Wet Flue Gas Desulfurization (FGD) ^{1,2,3}	Caustic/crushed limestone/lime slurry, scrubber vessel pressure drop, air injection blower, PM control device	\$2,200-\$4,700	Equipment, installation, engineering, reagent, energy use, and waste removal	All pulp and paper mill and beet manufacturing facility boilers

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

Table references:

1. *Applicability and Feasibility of NO_x, SO₂, and PM Emissions Control Technologies for ICI Boilers*, NESCAUM, November 2008.
2. *Midwest Regional Planning Organization Boiler BART Engineering Analysis*, LADCO, March 2005.
3. *BART Determination - Georgia Pacific Broadway Mill, Green Bay Wisconsin*, Wisconsin DNR, July 2011.

3.4.2.2 Time Necessary for 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 NO_x 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.

3.4.2.3 Energy and Non-Air Impacts

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 boilers. 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.

3.4.2.4 Remaining Useful Life at the Source

The remaining useful life of an individual boiler can vary greatly depending on the age of the boiler, size of the unit, maintenance frequency, and other factors. Life expectancies for most boilers at pulp and paper mills and beet manufacturing facilities are between 10 and 30 years or more.

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The Lake Michigan Air Directors Consortium (LADCO). *Midwest Regional Planning Organization Boiler Best Available Retrofit Technology Engineering Analysis*. March 30, 2005.

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4 Analysis of Selected Industrial, Commercial, and Institutional Boilers at Pulp and Paper Mills and Sugar Beet Manufacturing Facilities

4.1 Source Category Description

LADCO identified ten major facilities that contribute significant levels of NO_x and SO₂ in the northern Midwest region. Amec Foster Wheeler was directed by LADCO to evaluate these ten individual facilities with respect to four key source categories that contribute to visibility impairment: ICI boilers at pulp and paper mills and sugar beet manufacturing facilities, cement plants, lime plants, and pipeline transportation of natural gas. Of these ten facilities, seven are pulp and paper mills or sugar beet manufacturing facilities with ICI boilers. Table 4-1 and Table 4-2 list ICI boiler units that were identified for each facility utilizing a confidential unit ID for which a key is provided in the informational disc included with this report. Baseline NO_x and SO₂ emissions are provided for each unit.

4.2 Information Obtained from State Agencies

For the selected ICI boilers, Amec Foster Wheeler obtained current facility permits that were available online to evaluate the status of each unit. LADCO members provided supplemental information when permits were not readily available. Emissions inventory data for each facility were provided by each corresponding state.

Table 4-1 Source Category NOx Information Provided by LADCO

Unit ID	Unit Description	Heat Input (MMBtu/hr)	Fuel(s)	NOx Controls	Existing NOx Control Requirements	Baseline NOx Emissions (tpy)	Baseline Year
01-01	Boiler	202	Coal	Existing: None	None	263	2011
02-01	Boiler	660	Wood refuse, coal, natural gas	Existing: Over-fired air (OFA)	1. Heat Input Limit of 0.2 lb/mmBtu when firing NG; 0.70 lb/mmBtu (wood/coal) 2. 436.8 pound per hour (pph) when firing natural gas, wood, coal or any combination of these fuels including CVGs and/or DVGs	438	2011
03-01	Boiler	240	Pulverized coal, natural gas, biogas, No. 6 fuel oil	Existing: None	None	318	2011
03-02	Boiler	186	Pulverized coal, natural gas	Existing: None	Heat input limit of 0.2 lb/mmBtu when firing NG; 0.4 lb/mmBtu when firing No. 6 fuel oil; 0.7 lb/mmBtu when firing coal	91	2011
03-03	Boiler	227	Natural gas, biogas	Existing: Low-NOx burners	Heat input limit of 0.17 lb/mmBtu	47	2011
06-01	Boiler	356	Coal	Existing: None	Coke fines, used oil, and used oil sorbents fuel usage limits	360	2013

Table 4-1 Source Category NOx Information Provided by LADCO

Unit ID	Unit Description	Heat Input (MMBtu/hr)	Fuel(s)	NOx Controls	Existing NOx Control Requirements	Baseline NOx Emissions (tpy)	Baseline Year
06-02	Boiler	356	Coal	Existing: None	Coke fines, used oil, and used oil sorbents fuel usage limits	353	2013
08-01	Boiler	Unknown	Coal, wood	Existing: None	Heat input limit of 0.7 lb/mmBtu	219	2013
08-02	Boiler	Unknown	Coal, wood	Existing: None	Heat input limit of 0.7 lb/mmBtu	204	2013
09-01	Boiler	412.3	Coal, wood, NCG	Existing: None	Heat input limit of 0.8 lb/mmBtu	762	2011
09-02	Boiler	412.3	Coal, wood, NCG	Existing: None	Heat input limit of 0.8 lb/mmBtu	757	2011
10-01	Boiler	204	Bark, wood waste, paper pellets, natural gas, residual fuel oil, paper broke, TDF, sludge	Existing: None	None	40	2011
10-02	Boiler	192.4	Coal, pet coke, natural gas, No. 6 fuel oil, paper broke, TDF	Existing: None	None	391	2011
10-03	Boiler	379	Coal, pet coke, natural gas, No. 6 fuel oil, paper broke, TDF	Existing: None	None	1072	2011

Table 4-2 Source Category SO₂ Information Provided by LADCO

Unit ID	Unit Description	Heat Input (MMBtu/hr)	Fuel(s)	SO ₂ Controls	Existing SO ₂ Control Requirement	Baseline SO ₂ Emissions (tpy)	Baseline Year
01-01	Boiler	202	Coal	Current: None Future: Sorbent Dry Absorber (SDA)	Sulfur content limit of 1.5% by weight	808	2011
02-01	Boiler	660	Wood refuse, coal, natural gas	Current: None	1. SO ₂ limit of 476 pounds per hour (pph) 2. SO ₂ limit of 1,016 pph when incinerating CVGs from the lime kiln to the boiler 3. Heat input limit of 1.2 lb/mmBtu when firing coal	401	2011
03-01	Boiler	240	Pulverized coal, natural gas, biogas, No. 6 fuel oil	Current: None	Heat input limit of 1.67 lb/mmBtu when firing coal; 1.11 lb/mmBtu when firing No. 6 fuel oil	632	2011
03-02	Boiler	186	Pulverized coal, natural gas	Current: None	Heat input limit of 1.67 lb/mmBtu when firing coal; 1.11 lb/mmBtu when firing No. 6 fuel oil	387	2011
06-01	Boiler	356	Coal	Current: None	Coke fines, used oil, and used oil sorbents fuel usage limits	312	2013
06-02	Boiler	356	Coal	Current: None	Coke fines, used oil, and used oil sorbents fuel usage limits	290	2013
08-01	Boiler	Unknown	Coal, wood	Current: None	Heat input limit of 1.2 lb/mmbtu	71	2013
08-02	Boiler	Unknown	Coal, wood	Current: None	Heat input limit of 1.2 lb/mmbtu	51	2013

Table 4-2 Source Category SO₂ Information Provided by LADCO

Unit ID	Unit Description	Heat Input (MMBtu/hr)	Fuel(s)	SO ₂ Controls	Existing SO ₂ Control Requirement	Baseline SO ₂ Emissions (tpy)	Baseline Year
09-01	Boiler	412.3	Coal, wood, NCG	Current: None	1. Heat Input Limit of 1.2 lb/mmBtu when burning only wood waste and/or coal 2. Heat Input Limit of 1.2 lb/mmBtu when burning NCG, HVLC gas, and/or stripper off-gases 3. Heat Input Limit of 1.2 lb/mmBtu when burning used oil sorbents in combination with wood waste and/or coal 4. Heat Input Limit of 1.2 lb/mmBtu when burning used oil sorbents in combination with NCG, HVLC gas, and/or stripper off-gases	993	2011
09-02	Boiler	412.3	Coal, wood, NCG	Current: None	1. Heat Input Limit of 1.2 lb/mmBtu when burning only wood waste and/or coal 2. Heat Input Limit of 1.2 lb/mmBtu when burning NCG, HVLC gas, and/or stripper off-gases 3. Heat Input Limit of 1.2 lb/mmBtu when burning used oil sorbents in combination with wood waste and/or coal 4. Heat Input Limit of 1.2 lb/mmBtu when burning used oil sorbents in combination with NCG, HVLC gas, and/or stripper off-gases	915	2011

Table 4-2 Source Category SO₂ Information Provided by LADCO

Unit ID	Unit Description	Heat Input (MMBtu/hr)	Fuel(s)	SO ₂ Controls	Existing SO ₂ Control Requirement	Baseline SO ₂ Emissions (tpy)	Baseline Year
10-02	Boiler	192.4	Coal, pet coke, natural gas, No. 6 fuel oil, paper broke, TDF	Current: None Future: Sorbent Injection System (for HCl control) with mandatory baghouse use	1. Heat input limit of 7 lb/mmBtu over 24 hours and 5.5 lb/mmBtu over 30 days 2. Combined SO ₂ limit of 3865.4 lb/hr (over 24 hours) for No. 9 and No. 11 boilers 3. Sulfur content limit for No. 6 FO of 2.5% by weight 4. Sulfur content limit for coal blends of 4.4% by weight 5. Combined heat input limit of 1.7 lb/mmBtu for No. 9 and No. 11 boilers if the stack height is between 175 and 290 feet	1,786	2011
10-03	Boiler	379	Coal, pet coke, natural gas, No. 6 fuel oil, paper broke, TDF	Current: None Future: Sorbent Injection System (for HCl control) with mandatory baghouse use	1. Heat input limit of 7 lb/mmBtu over 24 hours and 5.5 lb/mmBtu over 30 days 2. Combined SO ₂ limit of 3865.4 lb/hr (over 24 hours) for No. 9 and No. 11 boilers 3. Sulfur content limit for No. 6 FO of 2.5% by weight 4. Sulfur content limit for coal blends of 4.4% by weight 5. Combined heat input limit of 1.7 lb/mmBtu for No. 9 and No. 11 boilers if the stack height is between 175 and 290 feet	4,899	2011

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5 Source Category Analysis for Kilns Located at Cement and Lime Plants

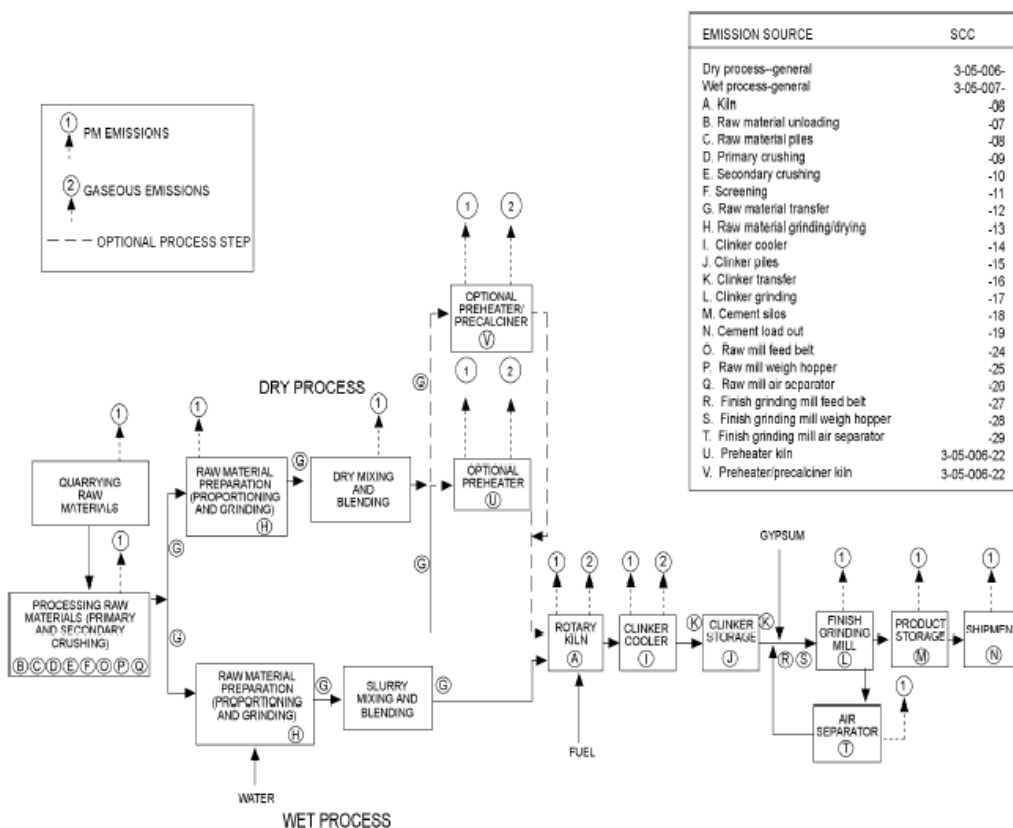
5.1 Source Category Description

The emission inventory and contribution assessment performed by LADCO demonstrated that NO_x and SO₂ emissions were key contributors to visibility impairment in Class I areas in the LADCO States. Specifically, kilns located at cement and lime plants were identified as large contributors of both pollutants.

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 SO₂ and NO_x. Crushing of ingredients and finished clinker can release dust and particles. Ammonia is sometimes produced during the heating of limestone.

Figure 5.1 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.

Figure 5.1 Portland Cement Process Flow Diagram



EPA. January, 1995. AP-42 Section 11.6 – “Portland Cement Manufacturing”.

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.

In the long dry process, all of the pyroprocessing activity occurs in the rotary kiln. 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 countercurrently 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 (ESP) that follow the raw mill is returned to the process, these devices are also considered to be 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 calciner vessel at the base of the preheater tower. This system is called the preheater/precalciner process.

The final component of the pyroprocessing system is the clinker cooler. The clinker cooler serves two main purposes. First, this portion of the process:

- 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.

The second portion of the clinker 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.

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. Our analysis of facilities in the LADCO states showed use of petcoke along with coal and other fuels.

Lime kilns are similar to cement kilns. The kiln is the heart of the lime manufacturing plant, where various fossil fuels (such as coal, petroleum coke, natural gas, and fuel oil) are combusted to produce the heat needed for calcination. There are five different types of kilns used in lime manufacturing: rotary, vertical, double-shaft vertical, rotary hearth, and fluidized bed. The most popular is the rotary kiln, however the double-shaft vertical kiln is an emerging new kiln technology gaining in acceptance primarily due to its energy efficiency. Similar to cement plants, rotary kilns at lime manufacturing plants may also have preheaters to improve energy efficiency. Additionally, energy efficiency is improved by routing exhaust from the lime cooler to the kiln. SO₂ emissions from lime predominately originate from compounds in the limestone feed material and fuels and are formed from the combustion of fuels and the heating of feed material in the kiln.

All types of kilns at lime manufacturing plants use external equipment to cool the lime product, except vertical (including double-shaft) kilns, where the cooling zone is part of the kiln. Ambient air is most often used to cool the lime (although a few use water as the heat transfer medium), and typically all of the heated air stream exiting the cooler goes to the kiln to be used as combustion air for the kiln. The exception to this is the grate cooler, where more airflow is generated than is needed for kiln combustion, and consequently a portion (about 40%) of the grate cooler exhaust is vented to the atmosphere. EPA has estimated that there are about five to ten kilns in the United States that use grate coolers. The emissions from grate coolers include lime dust (PM) and trace metallic HAPs found in the lime dust, but not typically SO₂.

5.2 NO_x from Kilns Located at Cement and Lime Plants

5.2.1 NO_x Emissions and 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 and lime kiln combustion depends on 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 in 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 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, RSCR, and SNCR. For lime manufacturing kilns, process tuning and/or optimization are currently the best control options. Cement kiln NO_x control options cannot be applied to lime manufacturing kilns due to smaller scale operation, different raw materials, and process conditions. Table 5-1 summarizes appropriate NO_x control options for cement and lime manufacturing kilns.

Table 5-1 Potential NOx Control Options for Cement and Lime Manufacturing Kilns

Technology	Description	Applicability	Performance
Tuning/Optimization ³	Process optimizing such as flame shaping and temperature profile	Potential control measure for all cement and lime manufacturing kilns	Varies
LNB ¹	Advanced burner design that controls oxygen, flame temperature, and/or residence time	Potential control measure for all cement and lime manufacturing kilns	10-20% reduction in NOx (for cement kilns; no data was found for lime kilns)
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 NOx
Mid-Kiln Firing ³	Injecting solid fuel (usually TDF) into mid-point of kiln system	Potential control measure for all cement kilns; dependent on fuels burned, kiln use, and kiln configuration	11-55% reduction in NOx
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 NOx
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 NOx
RSCR ⁴	A reducing agent such as ammonia is introduced into the flue gas stream to form nitrogen gas in the presence of a catalyst and heat exchangers	Potential control measure for all preheater and preheater/precalciner cement kilns; dependent on fuels burned, kiln use, and kiln configuration	75% reduction in NOx
SNCR ⁴	A reducing agent such as ammonia is introduced into the flue gas stream to form nitrogen gas	Potential control measure for all preheater and preheater/precalciner cement kilns; dependent on fuels burned, kiln use, and kiln configuration	45% reduction in NOx

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.

5.2.1.1 Combustion Modifications

Tuning/optimization

Kiln tuning and optimization is a baseline NO_x control that applies to both cement and lime manufacturing. This pre-combustion control includes improving fuel efficiency and tweaking with the kiln design to reduce NO_x emissions. Tuning/optimization is currently the most cost effective control for lime manufacturing kilns. 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 (LNB)/Indirect Firing

LNB reduce NO_x formation by controlling oxygen, flame temperature, and/or residence time. There are two general types of LNB: staged fuel and staged air. Staged fuel LNBs separate the combustion zone into a lean primary combustion region and a secondary combustion region. In the first zone, combustion takes place in excess oxygen, a small amount of fuel, and low burner temperatures. The remainder of the fuel is injected into the second zone and is mixed diffusively (as opposed to turbulently) with any remaining oxygen from the first combustion step for best NO_x reduction results. Staged fuel LNBs work particularly well for coal and natural gas kilns which exhibit higher thermal NO_x formation. Staged air LNB increases residence time and thus is more effective for fuel oil kilns which produce higher fuel NO_x emissions. LNBs can be used on all types of cement and lime manufacturing kilns except for vertical kilns (used in lime manufacturing) which are flameless.

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). No specific data was found for lime manufacturing kilns in respect to LNB. Indirect firing with LNB can be used on all systems in cement production. However, indirect firing has not been shown to reduce formation of NO_x in lime kilns (National Lime Association, 2005).

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 (e.g. TDF). 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. With preheater and preheater/precalciner systems, fuel is 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).

Mid-kiln firing cannot be applied to lime manufacturing kilns as the control can negatively impact the lime product. It will increase carry-over of unburned carbon into the product thus reducing its use in certain applications (National Lime Association, 2005).

5.2.1.2 Post-Combustion NO_x Controls

Selective Catalytic Reduction (SCR)

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 works best for preheater and/or precalciner kilns and can be applied to other types of cement kilns. The catalyst bed can be placed after the preheater tower 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. Application of SCR on cement kilns does not currently exist in North America but a long-term pilot project (Kirchdorf, Austria) along with three industrial applications (Solnhofen, Germany, Monselice, Italy, and Sarche di Calavino, Italy) exist in Europe (Environmental Quality Management, Inc., 2008). SCR NO_x reduction observed ranges from 70 to 90 percent.

Regenerative Selective Catalytic Reduction (RSCR)

RSCR™ is SCR with heat recovery. Industrial scale utility boilers burning biomass fuels have been shown to successfully utilize RSCR to control NO_x emissions. When installed on utility boilers, a heat exchanger system increases flue gas temperature before the gases enter the combustion chamber. Within the combustion chamber the temperature increases prior to entering the catalyst bed. Ammonia solution is injected prior to the catalyst. Babcock Power, Inc. has developed a RSCR system that is placed after the primary PM control. RSCR has

not been applied to cement kilns but could be applied assuming technology transfer with a calculated 75 percent NO_x reduction (Environmental Quality Management, Inc., 2010). RSCR application would work best for preheater and/or precalciner kilns because of the temperature requirement.

Selective Non-Catalytic Reduction (SNCR)

SNCR is another control option that is dependent on kiln type. Ammonia-containing solution (e.g. anhydrous ammonia, aqueous ammonia, or urea) is injected into the preheater tower for NO_x reduction. Optimum temperature ranges from 1600° to 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 ppm 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). SNCR has been used in both Europe and the US. SNCR is used in two precalciner plants in Sweden and at least 17 preheater plans mostly in Germany (Environmental Quality Management, Inc., 2010). The low cost ammonia reagent generally used in Europe is photowater, a waste product of film development containing 5.0 percent ammonia. In the US, SNCR systems are used in several preheater/precalciner plants with ammonia water or urea solution being used as the reagent.

5.2.2 Four Factor Analysis of Potential NO_x Control Scenarios for Cement and Lime Kilns

5.2.2.1 Cost of Compliance

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 or lime 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 5-2. 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. With mid-kiln firing, operating costs could be offset by refuse tipping fees for TDF. Site specific factors can impose additional costs.

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. 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 5-2 Cost Effectiveness for NOx Control Options for Cement and Lime Manufacturing Kilns

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	04-01, 05-01
LNB ¹	None	No data	Equipment, installation, and engineering	04-01, 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
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
RSCR ⁴	Specific temperature range, PM reduction, ammonia injection, catalyst, heat recovery, preheater kiln	\$5,500	Equipment, installation, engineering, energy use, waste removal, reduction agent, and catalyst	None
SNCR ⁴	Specific temperature range; PM reduction, ammonia injection, preheater kiln	\$1,400	Equipment, installation, engineering, energy use, waste removal, and reduction agent	None

^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. *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.

5.2.2.2 Time Necessary for 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. 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.

5.2.2.3 Energy and Other Impacts

When SCR, RSCR, and SNCR 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 SCR, RSCR, and SNCR, 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 an increase in waste disposal.

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.

5.2.2.4 Remaining Equipment Life

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.

REFERENCES

EC/R Incorporated. *NOx Control Technologies for the Cement Industry*. September 19, 2000.

Environmental Quality Management, Inc. *Control Technology Analysis Prepared for Carolinas Cement Company LLC*. February 25, 2008.

The Lake Michigan Air Directors Consortium (LADCO). *Midwest Regional Planning Organization Cement Best Available Retrofit Technology Engineering Analysis*. March 30, 2005.

Mid-Atlantic Regional Air Management Association, Inc (MARAMA). *Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas*. July 9, 2007.

National Lime Association. *Re: Comments on VISTAS's Draft Regional Haze Modeling Protocol*. October 21, 2005.

5.3 SO₂ from Kilns Located at Cement and Lime Plants

5.3.1 SO₂ Emissions and Control Options

Sulfur dioxide is formed from sulfur in fuels and raw materials. Sulfur content in fuels and raw materials can vary according to geographic location. In contrast to industrial boilers, SO₂ emissions from cement and lime manufacturing 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 both cement and lime production due to the alkaline nature of cement and limestone 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 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.

SO₂ emission reductions may also result from attempts to reduce other pollutants (primarily NO_x), typically due to changes in the flame characteristics of combustion. For example, staged combustion with mid-kiln injection of a low-sulfur fuel may be considered for reducing SO₂ in cement kilns. Since these techniques are primarily used to reduce NO_x and because their efficiencies are typically more limited than other techniques they are not considered in additional detail here.

Table 5-3Table 5-1 summarizes appropriate SO₂ control options for cement and lime manufacturing kilns.

Table 5-3 Potential SO₂ Control Technologies for Cement and Lime Manufacturing 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 and lime 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.

5.3.1.1 Flue Gas Desulfurization (FGD)

For cement kilns, control technology options identified for SO₂ include conventional dry FGD, wet FGD, and AFGD. For lime manufacturing kilns, both spray dry FGD and wet FGD control options have been suggested. Descriptions of each of these technologies are provided below. A summary of these controls is provided in Table 5-3.

Conventional Dry Flue Gas Desulfurization

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

In DSI, lime, calcium hydrate, limestone or soda ash is injected into the flue gas stream producing solid particles of 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. While technically feasible with lime kilns, there have not been any applications on lime kilns identified (VA DEQ, 2014).

In a 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). A lime manufacturing facility indicates that 90 percent reduction takes place when spray dryers are applied to lime plant kilns (VA DEQ, 2014).

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 (FGD)

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 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). No supporting information was found that indicated that present or potential use of AFGD in lime manufacturing kilns.

Wet Flue Gas Desulfurization (FGD)

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 caustic is used, liquid waste is produced and add-on waste collection equipment is minimal. When lime or limestone is used, additional steps and equipment are required to stabilize the watery calcium sulfite or calcium sulfate sludge produced. Fly ash is typically used to stabilize the calcium sulfite sludge.

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. A lime manufacturing facility indicates that 95 percent reduction takes place when wet FGD systems are applied to lime plant kilns (VA DEQ, 2014).

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.

5.3.2 Four Factor Analysis of Potential SO₂ Control Scenarios For Kilns

A four factor analysis approach has been utilized to analyze the potential control options presented in Table 5-3.

5.3.2.1 Cost of Compliance

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 5-4 summarizes the cost effectiveness and factors affecting 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 5-4 Cost Effectiveness for SO₂ Control Options for Cement and Lime Manufacturing Kilns

Control Option	Specific Design Parameters Identified	Cost Effectiveness (2015 \$/ton)^a	Factors Affecting Cost	Potential Applicability to Specific Facilities (Unit ID)
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	05-01
Conventional Dry Flue Gas Desulfurization (FGD) – Spray Dryer ^{1,5,6}	Absorption tower, lime slurry injection, PM control device	\$11,00 (lime) \$2,300-\$88,800 (cement)	Equipment, installation, engineering, reagent, and waste removal	04-01, 05-01
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	05-01
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	\$10,000 (lime) \$1,500-\$78,800 (cement)	Equipment, installation, engineering, reagent, energy use, and waste removal	04-01, 05-01

^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.
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.

5.3.2.2 Time Necessary for 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.

5.3.2.3 Energy and Non-Air Impacts

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.

5.3.2.4 Remaining Useful Life at the Source

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.

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Commonwealth of Virginia Department of Environmental Quality (VA DEQ). *Subject: Engineering Evaluation of Prevention of Significant Deterioration Permit Application Submitted by Carmeuse Lime & Stone for its Winchester Facility (Registration No. 80504)*. April 22, 2014.

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Florida Department of Environmental Protection. *Technical Evaluation & Preliminary Determination; Applicant Jacksonville Lime LLC*. December 31, 2013.

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VA DEQ. *Subject: Engineering Evaluation of Prevention of Significant Deterioration Permit Application Submitted by Carmeuse Lime & Stone for its Winchester Facility (Registration No. 80504)*. April 2014.

Washington State Department of Ecology. *BART Determination Support Document for Lafarge North America Seattle Plant*. October 2008.

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6 Analysis of Selected Kilns Located at Cement and Lime Plants

6.1 Source Category Description

LADCO identified ten major facilities that contribute significant levels of NO_x and SO₂ in the northern Midwest region. Amec Foster Wheeler was directed by LADCO to evaluate these ten individual facilities with respect to four key source categories that contribute to visibility impairment: ICI boilers at pulp and paper mills and sugar beet manufacturing facilities, cement plants, lime plants, and pipeline transportation of natural gas. Of these ten facilities, two are cement and lime plant sources. Table 6-1 and Table 6-2 list cement and lime kiln units that were identified for each facility utilizing a confidential unit ID. Baseline NO_x and SO₂ emissions are provided for each unit.

6.2 Information Obtained From State Agencies

For the selected cement and lime plants, Amec Foster Wheeler obtained current facility permits that were available online to evaluate the status of each unit. LADCO representatives provided supplemental information when permits were not readily available. Emissions inventory data for each facility were provided by each corresponding state.

Table 6-1 Point Source NOx Information Collected for Select Cement and Lime Kilns in the LADCO Region

Unit ID	Unit Description	Fuel(s)	NOx Controls ¹	Existing NOx Control Requirements ¹	Baseline NOx Emissions (tpy)	Baseline Year
04-01	Lime Kiln (Rotary with Preheater)	Coal, Pet Coke, No. 2 Fuel Oil, Propane	Existing: LNB (30% efficiency)	1. BACT NOx limit of 132.6 lb/hr (1.83 lb/ton stone feed) 2. NOx limit of 532 tpy	274	2011
05-01	Cement Kiln (Long Dry with Precalciner, Indirect Fired)	Coal, Pet Coke	Existing: SNCR and indirect firing	None ²	1,996	2011

1. Michigan Department of Environmental Quality. Personal communication regarding existing and future NOx and SO₂ controls at a lime manufacturing facility and a cement facility between Thomas R. Julien (517-284-6750, julient@michigan.gov) and Bill M. Hodan, Amec Foster Wheeler, Americas – Environment & Infrastructure, via E-mail on September 18, 2015.

2. Thomas R. Julien of MI DEQ indicated (in the correspondence mentioned above) that EPA determined that BART for the cement facility includes operation of the existing SNCR system for 50% reduction in NOx. Future limits of 2.80 lb NOx/ton clinker (30 day rolling average), 2.40 lbs NOx /ton clinker (12-month average), and 7.50 lbs SO₂/ton clinker (12-month average) will apply on January 1, 2017.

Table 6-2 Point Source SO₂ Information Collected for Select Cement and Lime Kilns in the LADCO Region

Unit ID	Unit Description	Fuel(s)	SO ₂ Controls ¹	Existing SO ₂ Control Requirements ¹	Baseline SO ₂ Emissions (tpy)	Baseline Year
05-01	Cement Kiln (Long Dry with Precalciner, Indirect Fired)	Coal, Pet Coke	Existing: None	None	1,942	2011
04-01	Lime Kiln (Rotary with Preheater)	Coal, Pet Coke, No. 2 Fuel Oil, Propane	Existing: Stone preheater and fabric filter (90-95% efficiency)	BACT SO ₂ limit of 55.2 lb/hr (0.83 lb/ton stone feed)	20	2011

1. Michigan Department of Environmental Quality. Personal communication regarding existing and future NOx and SO₂ controls at a lime manufacturing facility and a cement facility between Thomas R. Julien (517-284-6750, julient@michigan.gov) and Bill M. Hodan, Amec Foster Wheeler, Americas – Environment & Infrastructure, via E-mail on September 18, 2015.

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7 Source Category Analysis for Pipeline Transportation of Natural Gas

7.1 Source Category Description

Pipeline transportation of natural gas is dependent on compression stations located at key points within the pipeline network. The compression stations are required to maintain sufficient pressure to keep the natural gas flowing through the pipeline. These compression stations use Reciprocating Internal Combustion Engines (RICE) and turbines to generate power to run the compressors. Since natural gas is already available at compression stations it is the primary fuel used to drive these units. Use of RICE engines is the focus of our current evaluation since emissions from these engines result in a large contribution of NO_x to the emission inventories in the LADCO states. These engines are typically characterized as spark ignition internal combustion engines and therefore are subject to NSPS Subpart JJJJ if they were put in place in 2007 or 2008 (depending on engine configuration and power rating). Engines subject to NSPS Subpart JJJJ are required to comply with NO_x, CO, and VOC emissions limits. Additionally, any non-NSPS unit that is modified will become subject to NSPS JJJJ.

Since engines at compressor stations typically use natural gas for fuel, emissions of SO₂ are not large in comparison to other sources of SO₂ where higher sulfur fuels such as coal and fuel oils are used. Emissions of SO₂ and corresponding control options were not evaluated for this source category.

Most compression stations have emergency engines in place for backup power. These engines are not used often and their actual emissions of NO_x and SO₂ are low. Most other emissions associated with natural gas compressor stations are due to emissions of natural gas (VOC).

7.2 NO_x from Pipeline Transportation of Natural Gas

7.2.1 NO_x Emissions and Control Options

Nitrogen oxides are a by-product of combustion. Nitrogen is inherently contained in fuels and in the air and does not react at low temperatures. During combustion, the high temperatures cause the nitrogen and oxygen in the air to react and form NO_x. The amount of NO_x formed is dependent on many factors including the type of fuel combusted, temperature, and residence time of the air. NO_x formation from RICE at compressor stations can be classified into the following three categories: thermal NO_x, fuel NO_x, and prompt NO_x. Thermal NO_x is formed from nitrogen and oxygen in the air as a result of high temperature. Thermal NO_x formation has a positive correlation with temperature. Fuel NO_x is the result of nitrogen contained in organic fuels releasing and reacting with oxygen. Some fuels, such as natural gas, typically have no bound nitrogen, however, others such as fuel oil can contain high amounts. Prompt NO_x forms as atmospheric nitrogen, atmospheric oxygen, and hydrocarbons from the fuel rapidly react. It is a minor contributor to overall NO_x formation.

Pre-combustion NOx controls will not be evaluated as part of this analysis. A majority of the RICE at pipeline natural gas compressor stations are natural gas-fired and a lower nitrogen fuel suggestion is not feasible. There are two common combustion modifications that reduce NOx from RICE including air to fuel ratio adjustment and ignition/spark timing retard. Post-combustion NOx controls are also available for pipeline compressor station RICE and include non-selective catalytic reduction (NSCR), SNCR, and SCR. The applicability of each control technology is dependent on the type of engine - rich burn or lean burn - and the fuel combusted.

A summary of the control technologies analyzed in this report is provided in Table 7-1.

Table 7-1 Potential NOx Control Options for Pipeline Transportation of Natural Gas Sources

Technology	Description	Applicability	Performance
Air to Fuel Ratio Adjustment ¹	Increased air to fuel ratio lowers temperatures during combustion and reduces formation of thermal NOx.	Lean Burn RICE	5-30% reduction in NOx
Ignition/Spark Timing Retard ¹	Delaying the ignition event during a stroke lowers thermal NOx formation.	Lean Burn RICE	20% reduction in NOx
NSCR ^{1,2}	A three-way catalyst reduces NOx to nitrogen gas as well as lowers CO and VOC emissions.	Rich Burn RICE	80-95% reduction in NOx
SNCR ¹	A reducing agent such as ammonia is introduced to the exhaust gas stream to form nitrogen gas.	Rich and Lean Burn RICE	50-95% reduction in NOx
SCR ¹	A reducing agent such as ammonia is introduced into the exhaust gas stream to form nitrogen gas in the presence of a catalyst.	Lean Burn RICE	80-90% reduction in NOx

Table references:

1. *Colorado Visibility and Regional Haze State Implementation Plan for the Twelve Mandatory Class I Federal Areas in Colorado*, Appendix D. Colorado APCD. Jan 2011.
2. *A Pilot Project to Assess the Effectiveness of an Emission Control System for Gas Compressor Engines in Northeast Texas*. NETAC. Nov 2005.

7.2.1.1 Combustion Modifications

Air to Fuel Ratio Adjustment

Increasing the air to fuel ratio decreases thermal NO_x emissions in lean burn engines by reducing the temperature. Fuel-injected engines have the most NO_x reduction from air to fuel ratio adjustment. A turbocharger and air to fuel ratio controller are required to keep the engine operating efficiently due to the reduced fuel concentration. CO and VOC emissions increase as a result of the excess air. High energy ignition systems (HEIS) may be used to help with flame stability in low fuel, high air conditions (Colorado APCD, 2011). This combustion modification can decrease NO_x emissions by 5 to 30 percent in lean burn RICE depending on engine and loading type. It is not suitable for rich burn engines.

Ignition/Spark Timing Retard

Delaying the ignition event during a stroke reduces thermal NO_x emissions by increasing the volume in the cylinder at the time of ignition. For spark ignition engines, the timing of the spark is altered, and for compression engines, the timing of the fuel injection is altered. This control option is only suitable for lean burn engines. An electronic control system is required for RICE under variable loads to properly control ignition and injection. A reduction of 20 percent NO_x can typically be expected (Colorado APCD, 2014).

7.2.1.2 Post-Combustion NO_x Controls

Non-Selective Catalytic Reduction

In non-selective catalytic reduction (NSCR) systems, a catalyst reduces NO_x to nitrogen gas (N₂). The catalyst used is referred to as a three-way catalyst as it oxidizes hydrocarbon (HC) to water (H₂O) and carbon monoxide (CO) to carbon dioxide (CO₂) and reduces NO_x to N₂. According to a report prepared for Northeast Texas Air Care in 2005, NO_x emissions can be reduced by 90 percent using this technology. CO and HC emissions can also be reduced by 90 percent and 70 percent, respectively. NSCR systems are highly effective on rich burn engines only, as the oxygen levels are too high in lean burn engines.

Selective Non-Catalytic Reduction

SNCR reduces NO_x emissions by the injection of ammonia or urea into the exhaust stream. This reduces the NO_x to N₂ and water. Lean burn and rich burn engines can utilize this technology to achieve NO_x reductions of 50 to 95 percent. However, this technology is only appropriate for exhaust with temperatures greater than 1200 to 2000 °F, which may make it ineffective for variable load RICE such as those at natural gas compressor stations (EPA, 2000 and Colorado APCD, 2014). Ammonia slip occurs when the temperature of the exhaust gas is too low, like it would be during startup of the compressors.

Selective Catalytic Reduction

SCR removes NO_x by injecting ammonia or another reducing agent into the exhaust gas before the gases pass a catalyst. The catalyst lowers the activation energy needed for the reaction of NO_x and ammonia to form nitrogen gas and water. As a result, SCRs are appropriate for the lower exhaust gas temperatures and higher oxygen content exhaust of a lean burn engine. However, the same problem for SNCR systems exists for SCR systems in relation to variable load RICE such as those at natural gas compressor stations. The exhaust gas must be in a specific range to reduce NO_x and this is problematic when the exhaust temperature is not constant. Temperatures lower than the recommended for the catalyst result in ammonia slip. A properly operating SCR system can reduce NO_x emissions by 80 to 90 percent.

7.2.2 Four Factor Analysis of Potential NO_x Control Scenarios for Pipeline Transportation of Natural Gas Sources

A four factor analysis approach has been utilized to analyze the potential control options presented in Table 7-1.

7.2.2.1 Cost of Compliance

Information on cost effectiveness of retrofitting controls onto RICE at natural gas compressor stations 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 individual RICE specifications, use, and rating.

The costs from combustion modifications are primarily associated with the required add-on equipment. For air to fuel ratio adjustment, a turbocharger and electronic air to fuel ratio controller are necessary to maintain adequate efficiency and NO_x control. An electronic ignition control system is required to maintain NO_x reductions with ignition/spark timing retard.

For post-combustion NO_x controls, capital costs from the equipment and catalysts are the driving costs. There is little data on the cost effectiveness of retrofit SNCR systems for RICE due to the temperature constrictions making them less desirable than NSCR and SCR systems. SNCR would require reheating of the exhaust unlike NSCR and SCR.

Table 7-2 summarizes the cost effectiveness and factors affecting 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 increased or 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.

Table 7-2 Cost Effectiveness of NOx Control Options for Pipeline Transportation of Natural Gas Sources

Control Option	Specific Design Parameters Identified	Cost Effectiveness (2015 \$/ton)^a	Factors Affecting Cost	Potential Applicability to Specific Facilities (Unit ID)
Air to Fuel Ratio Adjustment ¹	None	\$350-\$9,200	Equipment (turbocharger, electronic air to fuel ratio controller), installation, and engineering	07-01, 07-02, 07-03
Ignition/Spark Timing Retard ¹	None	\$350-\$2,000	Equipment (electronic ignition control system), installation, engineering, and reduced efficiency	07-01, 07-02, 07-03
NSCR ^{1,2}	None	\$220-\$740	Equipment, installation, and engineering	None
SNCR ¹	None	No Data	Equipment, installation, engineering, energy use, waste removal, reduction agent, and catalyst	07-01, 07-02, 07-03
SCR ¹	None	\$430-\$4,900	Equipment, installation, engineering, energy use, waste removal, and reduction agent	07-01, 07-02, 07-03

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

Table references:

1. *Colorado Visibility and Regional Haze State Implementation Plan for the Twelve Mandatory Class I Federal Areas in Colorado*, Appendix D. Colorado APCD. Jan 2011.
2. *A Pilot Project to Assess the Effectiveness of an Emission Control System for Gas Compressor Engines in Northeast Texas*. NETAC. Nov 2005.

7.2.2.2 Time Necessary for Compliance

Facilities require time to design, purchase, and install selected control options in addition to the time needed to write and implement regulations. According to the Institute of Clean Air Companies, 13 months should be adequate for engineering to installation of SCR or SNCR systems for most RICE. Five years from conception to implementation would typically be appropriate, depending on the control options selected (Colorado APCD, 2014). Fuel and engine timing adjustments could be implemented within a year or two, depending on the age of the engine and availability of add-on electronics.

7.2.2.3 Energy and Non-Air Impacts

All of the NO_x control technologies available impact the efficiency of an engine. Fuel consumption may increase by up to 5 percent for combustion modifications and by less than one percent for SCR systems (Colorado APCD, 2014). Post-combustion NO_x controls reduce efficiency due to the pressure drop across the catalyst.

7.2.2.4 Remaining Useful Life at the Source

The remaining useful life of an individual RICE can vary greatly depending on many factors including the age, size, use, and maintenance frequency of the unit. No available data on the average life of existing RICE was found; however, in a four factor analysis prepared for the Western Regional Air Partnership (WRAP) in 2009, the projected lifetime of an SCR was used as a surrogate. The analysis assumed 15 years of life.

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Western Regional Air Partnership (WRAP) and Western Governors' Association (WGA). *Supplementary Information for Four Factor Analyses by WRAP States*. May 4, 2009.

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8 Analysis of Selected Pipeline Transportation of Natural Gas Facilities

8.1 Source Category Description

LADCO identified ten major facilities that contribute significant levels of NO_x and SO₂ in the northern Midwest region. Amec Foster Wheeler was directed by LADCO to evaluate these ten individual facilities in respect to four key source categories that contribute to visibility impairment: ICI boilers at pulp and paper mills and sugar beet manufacturing facilities, cement and lime plants, and pipeline transportation of natural gas. Of these ten facilities, one facility falls under the pipeline transportation of natural gas. Table 8-1 lists high NO_x contributing units that were identified utilizing a confidential unit ID. Baseline NO_x emissions are provided for each unit. Facilities in this category do not significantly contribute and are not reviewed in terms of SO₂ emissions.

8.2 Information Obtained From State Agencies

For the selected natural gas pipeline transport facility, Amec Foster Wheeler obtained the facility's current permit that was available online to evaluate the status of each unit in addition to the facility's 2013 emissions inventory that was provided by the corresponding state.

Table 8-1 Point Source Information Collected for Select Pipeline Transportation of Natural Gas Facilities in the LADCO Region

Unit ID	Unit Description	Heat Input (MMBtu/hr)	Fuel(s)	NOx Controls	Existing NOx Control Requirements	Baseline NOx Emissions (tpy)	Baseline Year
07-01	RICE	14	Natural gas	Existing: None	None	42	2013
07-02	RICE	14	Natural gas	Existing: None	None	33	2013
07-03	RICE	28	Natural gas	Existing: None	None	45	2013