

Assessment of Control Technology Options for BART-Eligible Sources

Steam Electric Boilers, Industrial Boilers,
Cement Plants and Paper and Pulp Facilities



Prepared by
Northeast States for Coordinated Air Use Management
In Partnership with
The Mid-Atlantic/Northeast Visibility Union

March 2005

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Submitted to the United States Environmental Protection Agency, Region III in partial fulfillment of requirements for USEPA grant **XA-983799-01-2** to the Ozone Transport Commission

March 2005

ASSESSMENT OF CONTROL OPTIONS FOR BART-ELIGIBLE SOURCES

**STEAM ELECTRIC BOILERS, INDUSTRIAL BOILERS,
CEMENT PLANTS, AND PAPER AND PULP
FACILITIES**

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Unit, Species, Acronyms

Acronyms

APCD – Air Pollution Control Device
BACT – Best Available Control Technology
BART – Best Available Retrofit Technology
CAA – Clean Air Act
CAAA – Clean Air Act Amendments
CKD – Cement Kiln Dust
CFBA – Circulating Fluidized-Bed Absorption
CFR – Code of Federal Regulations
DI – Dry Injection
DSI – Dry Sorbent Injection
EGU – Electricity Generating Unit
ESP – ElectroStatic Precipitator
ESFF – Electrostatic Stimulation of Fabric Filtration
FBC – Fluidized Bed Combustion
FF – Fabric Filters (also known as baghouses)
FGD – Flue Gas Desulfurization (also known as scrubbers)
FGR – Flue Gas Recirculation
FOM – Fixed Operating and Maintenance Costs
ICR – Information Collection Request
LAER – Lowest Achievable Emission Rate
LNB – Low NO_x Burner
LSFO – Limestone Forced Oxidation
LSC – Low Sulfur Coal (also known as “compliance coal”)
MACT – Maximum Achievable Control Technology
MANE-VU – Mid-Atlantic/Northeast Visibility Union
MC – Mechanical Collector
NCG – Non Condensable Gases
NESCAUM – Northeast States for Coordinated Air Use Management
NSPS – New Source Performance Standard
NSR – New Source Review
OFA – Over Fire Air
PC – Pulverized Coal
PS – Particulate Scrubber
RACT – Reasonably Available Control Technology
RPO – Regional Planning Organization
SIP – State Implementation Plan
SCR – Selective Catalytic Reduction
SDA – Spray Dry Absorption
SNCR – Selective Non-Catalytic Reduction
SOG – Stripper Off Gases
TDF – Tire-Derived Fuel
US EPA – United States Environmental Protection Agency

Chemical Species

EC – elemental carbon

HSO₄ – bisulfate

H₂SO₄ – sulfuric acid

HNO₃ – nitric acid

NO_x – oxides of nitrogen (NO and NO₂)

NO – nitric oxide

NO₂ – nitrogen dioxide

NO₃ – nitrate

NH₃ – ammonia

(NH₄)₃H(SO₄)₂ – letovicite

NH₄HSO₄ – ammonium bisulfate

(NH₄)₂SO₄ – ammonium sulfate

NH₄NO₃ – ammonium nitrate

OC – organic carbon

PM_{2.5} – particle matter up to 2.5 μm in size

PM₁₀ – particle matter up to 10 μm in size

PM_{coarse} – the difference: PM₁₀ – PM_{2.5}

S – sulfur

Se – selenium

SO₂ – sulfur dioxide

SO₄ – sulfate

VOC – volatile organic carbon

VOM – Variable Operating and Maintenance Costs

Units

Length

m – meter

μm – micrometer (0.000001m; 10⁻⁶m)

km – kilometer (1000 x m; 10³ m)

Mm – Megameter (1000000 x m; 10⁶ m)

Flow Rate

ACFM – Actual Cubic Feet per Minute

Volume

L – liter

m³ – cubic meter

Mass

lb – pound

g – gram

μg – micrograms (0.000001 x g; 10⁻⁶ g)

kg – kilograms (1000 x g; 10³ g)

Power

W – watt (Joules/sec)

kW – kilowatt (1000 x W; 10^3 W)

MW – megawatt (1000000 x W; 10^6 W)

Energy

Btu – British Thermal Unit (= 1055 Joules)

mmBtu – million Btu

MWh – megawatt hour

kWh – kilowatt hour

Concentration

$\mu\text{g}/\text{m}^3$ – micrograms per cubic meter

Visibility

dv – deciview

km – visual range in kilometers

Mm^{-1} – extinction in inverse megameters

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Executive Summary

This report was prepared by the Northeast States for Coordinated Air Use Management (NESCAUM) as part of an effort to assist states and tribes as they prepare to comply with the Best Available Retrofit Technology Requirements (BART) of the Regional Haze Rule. The Haze Rule requires states to determine the most stringent technologically feasible system of controls that can reasonably be installed at each facility eligible for BART. Criteria that determine whether a specific control technology is deemed reasonable include: cost of the controls, other control technology in use at the source, energy and other non-air quality environmental impacts, remaining useful life of the source as well as the degree of visibility improvement anticipated to result from installation of the controls.

This assessment provides information on available technology options, control efficiency and typical installation costs for four important BART-eligible source categories in the MANE-VU region. These categories include Fossil-fuel fired steam electric plants of more than 250 million British thermal units per hour heat input, Fossil-fuel boilers of more than 250 million British thermal units per hour heat input, Portland cement plants, and Kraft pulp mills. While there are 22 other source categories covered by the BART rule (with over 25 BART-Eligible facilities in at least 8 of these source categories in the MANE-VU region), we have chosen to focus on these four categories which include 75 of the 100 MANE-VU BART-Eligible sources identified at this time. *[Editors note: The addition of NY and PA non-EGU facilities will change these numbers]* These source sectors were chosen for a combination of factors including the number of facilities, the typical emission level for these type of facilities and the availability of a generic control technology characterizations for that sector. States will need to conduct an individual analysis for each facility prior to making a BART determination. This information is intended to facilitate that process by collecting available technology information in a single reference document.

The report finds that significant emissions reductions can be achieved through a variety of technologies that target different haze forming pollutants. While wet and dry scrubbing techniques may be cost-effective means of removing SO₂ at EGUs and large industrial boilers, combustion modifications and process changes might be more effective at cement plants and paper and pulp facilities. Similarly for NO_x control, SCR and SNCR are very efficient methods of post-combustion control that can be quite cost-effective on large boilers, but combinations of combustion and post-controls as well as combustion modification and process changes are also viable means of reducing a facility's total NO_x emissions. These approaches need to be carefully considered on a unit-by-unit basis, taking into account fuel used (coal, natural gas, oil, wood, etc.) and capacity or use factors, to ensure that product quality and pollutant co-control issues are handled appropriately. Particulate controls include a variety of technologies, but electrostatic precipitators and fabric-filters (or baghouses) are viable options in different configurations for EGUs, industrial boilers and cement plants. Paper and pulp facilities may also consider demister pads, packed tower technologies and Venturi scrubbers.

1. INTRODUCTION

Under the U.S. Environmental Protection Agency’s (USEPA) 1999 “regional haze rule” [64 Fed. Reg. 35714 (July 1, 1999)], certain emission sources that “may reasonably be anticipated to cause or contribute” to visibility impairment in downwind Class I areas are required to install Best Available Retrofit Technology (BART).¹ These requirements are intended to reduce emissions specifically from large sources that, due to age, were exempted from other control requirements of the Clean Air Act (CAA).

BART requirements pertain to 26 specified major point source categories, including power plants, industrial boilers, paper and pulp plants, cement kilns and other large stationary sources. To be considered BART-eligible, sources from these specified categories must have the potential to emit at least 250 tons per year of any haze forming pollutant and must have commenced operation or come into existence in the fifteen year period prior to August 7, 1977 (the date of passage of the 1977 Clean Air Act Amendments (CAAA), which first required new source performance standards).

Because of the regional focus of the 1999 haze rule, it is likely that BART requirements will be applied to a much larger number of sources across a broader geographic region than has been the case historically (i.e. through reasonably attributable visibility impairment requirements in the 1980 haze regulations). In addition, USEPA has for the first time introduced the possibility that source-by-source, command and control type BART implementation may be replaced by more flexible, market-based approaches, provided such alternatives can be shown to achieve *greater* progress toward visibility objectives than the standard BART approach.

In developing future haze state implementation plans (SIPs), states and tribes will need to include an inventory of emissions from potentially BART-eligible facilities in their jurisdictions and specify the timetable and stringency of controls to be applied at those sources. In determining what level of control represents BART, states must address the following considerations for each eligible source or group of eligible sources:

- Compliance costs,
- Energy and non-air quality environmental impacts,
- Any existing pollution control technology in use at the source,
- The remaining useful life of the source, and
- The degree of visibility improvement that may reasonably be anticipated to result from the imposition of BART.

In many respects, the strength of the BART program is dependent upon the interpretation of these factors and in January 2001 USEPA proposed guidelines for the interpretation and implementation of Best Available Retrofit Technology (BART) requirements, including these factors. While no explicit threshold was established for

¹ There are seven designated Class I areas in the Northeast and Mid-Atlantic States. They include Acadia National Park and Moosehorn Wilderness Area in Maine; Roosevelt-Campobello International Park in New Brunswick and Maine; the Lye Brook Wilderness Area in Vermont; the Great Gulf and Presidential Range-Dry River Wilderness Areas in New Hampshire; and the Brigantine Wilderness Area in New Jersey.

any of these factors, the publication of the BART guidelines as a proposed rule in the Federal Register [66 Fed. Reg. 38108 (July 20, 2001)] initiated a formal rulemaking process to clarify BART requirements specifically.

BART is the primary mechanism identified for regulating haze-forming pollutants from stationary sources for the first implementation period under the Haze Rule and the final BART regulations, anticipated to be published on April 15, 2005, gives urgency to understanding the implications of the final BART guidelines with respect to state planning efforts. Depending on a host of factors, BART may be the primary component of state haze plans or may be eliminated as a potential mechanism for state compliance.² Amid such uncertainty, states must continue to plan for the implementation of BART.

To assist MANE-VU states and tribes with BART implementation efforts, MANE-VU has developed a list of BART-eligible sources in the region (NESCAUM, 2001; NESCAUM, 2003).³ The preliminary list developed in these documents has been refined by state permitting staff to verify identifications and determine eligibility for those sources for which incomplete information was available. The final, state-approved (i.e. each state has approved the list of sources within that state) list is available here as Appendix A. It should be noted that the review of the facilities for BART eligibility was performed prior to the release of the draft BART rule in 2004. Determinations were based upon the guidance provided in EPA draft rule released in 2001. It is anticipated that EPA will release a final BART rule in April 2005 and at that time final BART-eligibility determinations will be made. It is likely that there will be changes to the BART list based upon that final rule.

Once deemed BART-eligible, each source will undergo a BART engineering review to determine what system of controls constitutes BART for each facility. This review will examine impacts for all the BART pollutants. For example, if a facility triggers BART because it has VOC emissions over 250 tons per year for date-eligible units, the facility will also have to examine the impacts of emissions of NO_x, SO₂, PM₁₀ and ammonia, even if emissions of these pollutants are less than 250 tons per year.

In addition, this review must take into account the statutory factors cited earlier including remaining useful life of a source and controls already in place at a source. After review of these criteria and control options, the level of required control will be established. It is anticipated that the final rule will also address the specific aspects relating to the completion of a BART engineering analysis.

² A number of factors in the pending BART regulation may affect the strength of the program. Among these are (1) a final decision on whether USEPA's Clean Air Interstate Rule (CAIR) could serve as BART for affected sources in states that choose this option, (2) final rules for how states may institute a source-by-source exemption test, (3) a decision on whether to aggregate emissions from multiple date-eligible boilers at a facility when comparing to the 250 ton/year emission threshold. An additional factor to consider is a provision contained in Senate Resolution 485 (the Clear Skies Act of 2003 which is expected to be re-introduced early in the 109th congress), which would act in place of the BART requirements of the regional haze rule.

³ NESCAUM does not believe that there are any BART-eligible sources in the State of Vermont or any of the member Tribes in MANE-VU and thus we have not developed lists for these jurisdictions. In addition, Pennsylvania and the District of Columbia have developed BART-Eligible source lists following their own methodology and the identified sources are contained in the final list in Appendix A.

As a next step in coordinating BART determinations for MANE-VU states and tribes, we present here (in Chapters 3 through 6 of this report) a preliminary assessment of available control technology options for states to consider as they undertake the specific BART determinations for each of the eligible facilities in four major source categories including EGUs, industrial boilers, cement plants and paper and pulp facilities. These four categories cover 76 of the 101 BART-eligible facilities in MANE-VU.

While a facility specific review will need to be undertaken for each BART-eligible facility (either to determine BART controls to be installed, or to determine the magnitude of emissions reductions that must be considered in a BART trading program), the information provided here will give states and tribes a foundation for conducting these reviews.

2. STEAM ELECTRIC PLANTS (EGUs)

Electricity Generating Units or EGUs are the largest source category among the twenty-six source categories covered by the Regional Haze Rule both in terms of total visibility impairing emissions and in terms of number of facilities. Estimates of national emissions for criteria air pollutants prepared by the USEPA show that electric utility power plants that burn coal are significant sources of sulfur dioxide (SO₂), nitrogen oxides (NO_x), and particulate matter (PM) (USEPA, 2000). Electric utility power plants are the nation's largest source of SO₂ emissions, contributing approximately 68 percent of the estimated total national SO₂ emissions in 1998 (most recent year for which national estimates are available). Over 90 percent of these SO₂ emissions are coal-fired electric utility boilers. Electric utilities contributed 25 percent of total national NO_x emissions in 1998. Again coal combustion is the predominant source of NO_x emissions from the electric utilities (almost 90 percent of the estimated NO_x emissions). Coal-fired electric utility power plants also are one of the largest industrial sources of PM emissions. In general, the high combustion efficiencies achieved by coal-fired electric utility boilers result in low emissions of CO and volatile organic compounds (a precursor for the photochemical formation of ozone in the atmosphere). Although the emphasis of this Chapter is on coal-fired utility boilers, many technologies described here are also applicable to gas and oil-fired units (for example, SCR and SNCR technologies are equally applicable to coal and natural gas/oil units, generally at much lower capital and operating costs; same is true for wet scrubbers for SO₂ control and ESPs or baghouses for PM control for oil units).

All coal-fired electric utility power plants in the United States use control devices to reduce PM emissions. Many coal-fired electric utility boilers also are required to use controls for SO₂ and NO_x emissions depending on site-specific factors such as the properties of the coal burned, when the power plant was built, and the area where the power plant is located. Though there are other major stationary source sectors (for example, cement plants, paper and pulp plants, large industrial boilers, combustion turbines, iron and steel industry), coal-fired boilers are by far the largest contributor of all of these three precursors of regional haze.

2.1. Description of generation process and typical technologies

The USEPA ICR (Information Collection Request) of 1999 (the most recent and quite detailed survey of coal-fired EGUs in the U.S. completed in connection with USEPA efforts to develop MACT regulations for mercury from EGUs) indicates that there were about 1,140 coal-fired units in the U.S. (with a maximum capacity to generate in excess of 300,000 MW of power). This USEPA ICR data indicated that coal-fired steam electric generating units in the U.S. burned 786 million tons of coal of which, approximately 52 percent was bituminous and 37 percent was sub-bituminous. Other fuels included lignite, anthracite coal, reclaimed waste coal, mixtures of coal and petroleum coke (pet-coke), and mixtures of coal and tire-derived fuel (TDF). Pulverized coal-fired (PC) boilers represent approximately 86 percent of the total number and 90 percent of total utility boiler capacity. Based on capacity, other types of boilers include cyclone-fired boilers (7.6 percent), fluidized-bed combustors (1.3 percent), and stoker-fired boilers (1.0 percent).

2.2. Review of BART-Eligible EGUs in the MANE-VU Region

There are 53 BART-Eligible EGUs in the MANE-VU region. Table II-1 contains a summary list of these sources by state. A complete list is presented in Appendix A. Both lists are based on a previous NESCAUM report (2001) and follow-up review by state permitting authorities.⁴ An estimated 1.2 million tons of SO₂ and three-hundred thousand tons of NO_x are emitted by these facilities and given the available control technology described in subsequent sections of this chapter, BART-Eligible EGUs represent a significant emissions reduction potential for consideration in the regional haze planning process.

Table II-1 BART-Eligible EGUs in the MANE-VU region. (NESCAUM, 2001).

State	Total Number of BART EGUs	Total SO₂ Emissions (1999 NEI)	Total NO_x Emissions (1999 NEI)
Connecticut	5	30,787	8,217
Delaware	3	10,490	4,465
District of Columbia	1	1,432	447
Maryland	6	177,678	63,767
Massachusetts	7	97,854	27,350
Maine	1	6,406	879
New Hampshire	2	37,834	7,043
New Jersey	1	17,260	7,891
New York	13	73,164	31,392
Pennsylvania	14	744,165	151,992
Penobscot Tribe	0	N/A	N/A
Rhode Island	0	N/A	N/A
St. Regis Mohawk Tribe	0	N/A	N/A
Vermont	0	N/A	N/A
Region Total	53	1,197,070	303,443

2.3. Available Control Technologies

A variety of emission control technologies are employed to meet requirements for SO₂, NO_x, and primary PM emissions; the three major precursors of observed regional haze in the atmosphere (SO₂ and NO_x are mostly converted to ammonium sulfate and ammonium nitrate

⁴ NESCAUM does not believe that there are any BART-eligible sources in the State of Vermont or any of the member Tribes in MANE-VU and thus we have not developed lists for these jurisdictions. In addition, Pennsylvania and the District of Columbia have developed BART-Eligible source lists following their own methodology and any identified sources are contained here and in the final list in Appendix A.

that are formed by the reactions of precursor gases with ammonia in the environment that is emitted mostly from agricultural and cattle related activities). Most utilities control SO₂ by the use of either low-sulfur coal (generally less than 1 percent sulfur by weight) or by wet or dry scrubbing (known as flue gas desulfurization, or FGD). Generally, NO_x emissions are controlled via combustion modification and, more recently, by more advanced post-combustion controls, which are required by the 1990 Clean Air Act and state regulations (“NO_x Transport SIP Call” and the Title IV of the 1990 CAAA are two major examples). Compared to these two precursors, PM emissions are almost universally controlled in the U.S. (almost 100% of units have either electrostatic precipitators (ESPs) or fabric filters (FF) (popularly known as “bag houses”). Based on the 1999 USEPA’s ICR (Information Collection Request) data, for post-combustion controls, 77.4 percent of the units have PM control only, 18.6 percent have both PM and SO₂ controls, 2.5 percent have PM and NO_x controls, and 1.3 percent have all three post-combustion control devices.

The different types of post-combustion control devices are briefly described below with detailed descriptions given later in this section:

SO₂ post-combustion control technologies are systems that are classified as wet flue gas desulfurization (FGD) scrubbers, semi-dry scrubbers, or dry injection. Wet FGD scrubber controls remove SO₂ by dissolving it in a solution. A PM control device is always located upstream of a wet scrubber. PM devices that may be used with wet FGD scrubbers include a Particulate Scrubber (PS), Cold Side (CS)-ESP, Hot Side (HS)-ESP, or a fabric filter (FF) or a baghouse. Semi-dry scrubbers include spray dryer absorption (SDA). Dry injection involves injecting dry powdered lime or other suitable sorbent directly into the flue gas. A PM control device (ESP or FF) is always installed downstream of a semi-dry scrubber or dry injection point to remove the sorbent from the flue gas.

NO_x post-combustion control technologies include selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) processes. With both of these methods, a reducing agent such as ammonia or urea is injected into the duct to reduce NO_x to N₂. SCR operates at lower temperatures than SNCR and is much more effective at reducing NO_x, but it has higher capital costs for installation.

Particulate matter (PM) control technologies include electrostatic precipitators (ESPs), fabric filters (FFs) (also called “baghouses”), and particulate scrubbers (PS). ESPs and FFs may be classified as either cold-side (CS) devices [installed upstream of the air heater where flue gas temperatures range from 284 to 320 °F (140 to 160 °C)] or hot-side [installed downstream of the air heater and operate at temperatures ranging from 662 to 842 °F (350 to 450 °C)].

For PM controls, ESPs are used on 84 percent of the existing electric utility coal-fired boiler units, and fabric filters or baghouses are used on 14 percent of the utility units. Post-combustion SO₂ controls are less common. Wet flue gas desulfurization (FGD) systems are used on 15.1 percent of the units; and, dry scrubbers, predominantly spray dryer absorbers (SDA), are used on 4.6 percent of units that were surveyed. However, since it is generally more cost effective to install scrubbers on big units, the 20 percent of the units represent about 30% of the installed U.S. capacity. In response to the “Section 110 Transport SIP call” and the implementation of the Federal Title IV acid rain program, the application of post-combustion NO_x controls is becoming more prevalent. For example, based on the current status of electric utility industry, it appears that one third of the coal-based capacity (about 100,000 MW out of the

installed base of about 300,000 MW) has been or is currently being retrofitted with the advanced SCR technology .

2.3.1. Emission Characteristics of Regional Haze Precursors from Coal Combustion

Sulfur Dioxide

SO₂ emissions, mostly from the combustion of fossil fuels and by metallurgical processes, are the result of oxidation of sulfur in the coal during the combustion process. Coal deposits contain sulfur in amounts ranging from trace quantities to as high as eight percent or more. Most of this sulfur is present as either pyritic sulfur (sulfur combined with iron in the form of a mineral that occurs in the coal deposit) or organic sulfur (sulfur combined directly in the coal structure). During combustion, sulfur compounds in coal are oxidized to gaseous SO₂ or SO₃. When firing bituminous coal, almost all of the sulfur present in coal is emitted as gaseous sulfur oxides (on average, ninety eight percent). The more alkaline nature of ash in some subbituminous coals causes a portion of the sulfur in the coal to react to form various sulfate salts; these salts are emitted as fly ash or retained in the boiler bottom ash. Generally, the percentage of sulfur in the as-fired coal that is converted to sulfur oxides during combustion does not vary with the utility boiler design or operation. (USEPA, 1982; Buonicore and Davis, 1992).

Nitrogen Oxides

The NO_x formed during coal combustion by oxidation of molecular nitrogen (N₂) in the combustion air is referred to as “thermal NO_x.” The oxidation reactions converting N₂ to NO and NO₂ become very rapid once gas temperatures rise above 1,700°C (3,100°F). Formation of thermal NO_x in a coal-fired electric utility boiler is dependent on two conditions occurring simultaneously in the combustion zone: high temperature and an excess of combustion air. A boiler design feature or operating practice that increases the gas temperature above 1,700 °C, the gas residence time at these temperatures and the quantity of excess combustion air affects thermal NO_x formation. The formation of NO_x by oxidation of nitrogen compounds contained in the coal is referred to as “fuel NO_x.” The nitrogen content in most coals ranges from approximately 0.5 to 2 percent. The amount of nitrogen available in the coal is relatively small compared with the amount of nitrogen available in the combustion air. However, depending on the combustion conditions, significant quantities of fuel NO_x can be formed during coal combustion. (USEPA, 1991; Buonicore and Davis, 1992).

Both NO and NO₂ are formed during coal combustion by oxidation of molecular nitrogen that is present in the combustion air or nitrogen compounds contained in the coal. Overall, total NO_x formed during combustion is composed predominantly of NO mixed with small quantities of NO₂ (typically less than 10 percent of the total NO_x formed). However, when NO is formed during coal combustion, the NO is oxidized to NO₂ and is emitted to the atmosphere.

Particulate Matter

Primary PM emissions from coal-fired electric utility boilers consist primarily of fly ash. Ash is the unburned carbon char and the mineral portion of combusted coal. The amount of ash in the coal, which ultimately exits the boiler unit as fly ash, is a complex function of the coal properties, furnace-firing configuration, and boiler operation. For the dry-bottom, pulverized-coal-fired boilers, approximately 80 percent of the total ash in the as-fired coal exits the boiler as fly ash. Wet-bottom, pulverized-coal-fired boilers emit significantly less fly ash: on the order of 50 percent of the total ash exits the boiler as fly ash. In a cyclone furnace boiler, most of the ash is retained as liquid slag; thus, the quantity of fly ash exiting the boiler is typically 20 to 30 percent of the total ash. However, the high operating temperatures unique to these designs may also promote ash vaporization and larger fractions of submicron fly ash compared to dry bottom designs. Fluidized-bed combustors emit high levels of fly ash since the coal is fired in suspension and the ash is present in dry form. Spreader-stoker-fired boilers can also emit high levels of fly ash. However, overfeed and underfeed stokers emit less fly ash than spreader stokers, since combustion takes place in a relatively quiescent fuel bed.

In addition to the fly ash, PM emissions from coal-fired EGUs result from reactions of the SO₂ and NO_x compounds as well as unburned carbon particles carried in the flue gas from the boiler. The SO₂ and NO_x compounds are initially in the vapor phase following coal combustion in the furnace chamber but can partially chemically transform in the stack, or near plume, to form fine PM in the form of nitrates, sulfur trioxide (SO₃), and sulfates. Firing configuration and boiler operation can affect the fraction of carbon (from unburned coal) contained in the fly ash. In general, the high combustion efficiencies achieved by pulverized-coal-fired boilers and cyclone-fired boilers result in relatively small amounts of unburned carbon particles in the exiting combustion gases. Those pulverized-coal-fired electric utility boilers that use special burners for NO_x control tend to burn coal less completely; consequently, these furnaces tend to emit a higher fraction of unburned carbon in the combustion gases exiting the furnace.

Another potential source of PM from coal-fired EGUs can be found in the flue gas and the use of a dry sorbent-based control technology. Solid sorbent particles are injected into the combustion gases to react with the air pollutants and then recaptured by a downstream control device. Sorbent particles that escape capture by the control device are emitted as PM to the atmosphere. (USEPA, 1982; Buonicore and Davis, 1992).

2.3.2. Control Technologies used for Coal-fired EGUs

In addition to BART requirements, all EGUs in the U.S. must comply with applicable federal and state standards and programs that specifically regulate criteria air emissions from coal-fired electric utility boilers. The federal regulations and programs include New Source Performance Standards (NSPS), the CAA Title IV Acid Rain Program, the 1997 “Transport NO_x SIP call,” and the CAA Title V Operating Permits Program. The USEPA has delegated authority to individual state and local agencies for implementing many of these regulatory requirements

Additionally, some of the states in the Northeast, including Connecticut, Massachusetts, New Hampshire, New Jersey, and New York, have recently implemented new regulations or legislation that are more stringent than the federal requirements. Electric utility companies use one or a combination of the following three control strategies to comply with the specific set of requirements applicable to a given coal-fired boiler.

Pre-combustion Controls. Control measures in which fuel substitutions are made or fuel pre-processing is performed to reduce pollutant formation in the combustion unit.

Combustion Controls. Control measures in which operating and equipment modifications are made to reduce the amount of pollutants formed during the combustion process; or in which a material is introduced into the combustion unit along with the fuel to capture the pollutants formed before the combustion gases exit the unit.

Post-combustion Controls: Control measures in which one or more air pollution control devices are used at a point downstream of the furnace combustion zone to remove the pollutants from the post-combustion gases.

Table II-2 shows the national distribution of emissions control strategies for SO₂, NO_x, and PM used for coal-fired electric utility boilers in 1999 as reported in the Part II USEPA ICR data (USEPA, 2001). Approximately two-thirds of the total coal-fired electric utility boilers use either a low-sulfur fuel or a post-combustion technology (a wet or a dry scrubber) to control SO₂ emissions. The methods used for controlling SO₂ emissions from EGUs are discussed first. All coal-fired electric utility boilers in the United States are controlled for PM emissions by using some type of post-combustion controls. These particulate emission control types are discussed next. Although approximately two-thirds of the coal-fired electric utility boilers are controlled for NO_x emissions, these units are not necessarily the same units controlled for SO₂ emissions. The predominant strategy for controlling NO_x emissions is to use combustion controls. Later in this section, the application of NO_x emission controls to coal-fired electric utility boilers is described in detail.

Table II-2 Criteria air pollutant emission control strategies as applied to coal-fired electric utility boilers in the United States for the year 1999 (USEPA, 2001).

Criteria Air Pollutant	Percentage of Coal-fired Electric Utility Boilers Using Control Strategy as Reported in Phase II USEPA ICR Data a,b			
	Meet Applicable Standards Without Additional Controls	Pre-combustion Controls	Combustion Controls	Post-combustion Controls
Particulate Matter	0 %	0 %	0 %	100 %
Sulfur Dioxide	37 %	40 %	3 %	20 %
Nitrogen Oxides	40 %	0 %	57 %	3 %

(a) Approximately 1.5 % of the boilers use a combination of pre-combustion and post-combustion SO₂ controls.

(b) Approximately 1% of the boilers using post-combustion NO_x controls also use some type of combustion controls.

SO₂ Emission Controls

Sulfur dioxide emissions from most coal-fired electric utility boilers are controlled using either of two basic approaches. The first approach is to use pre-combustion measures, namely, firing coal that contains lower amounts of sulfur. The low-sulfur coal may be naturally occurring or the result of coal cleaning. The other approach is to remove the sulfur compounds from the flue gas before the gas is discharged to the atmosphere. These post-combustion processes are collectively called “flue gas desulfurization” or “FGD” systems. All FGD systems can be further classified as wet or dry flue gas scrubbing systems. The SO₂ control approaches include a number of different technology subcategories that are now commercially used in the United States, Europe, or Pacific Rim countries.

Table II-3 presents the 1999 nationwide distribution of SO₂ controls used for coal-fired electric utility boilers by total number of units and by percentage of nationwide electricity generating capacity. For approximately one-third of the boilers, no SO₂ controls were reported in the Part II USEPA ICR data. The other two-thirds of the units reported using some type of control to meet the SO₂ emission standards applicable to the unit. Pre-combustion control by burning a low-sulfur content coal was reported for approximately 40 percent of the boilers. Post-combustion control devices for SO₂ removal are used for approximately 20 percent (representing 30% of the capacity in megawatts) of the boilers. Wet FGD systems are the most commonly used post-combustion control technique. The newer technologies of spray dryer systems or dry

injection are limited in their application to existing units. The remaining 3 percent of the boilers use fluidized-bed combustion (FBC) with limestone.

Low-sulfur Coal

Coal with low sulfur content can be burned and meet applicable SO₂ emission standards without the use of additional controls is sometimes referred to as “compliance coal.” Coals naturally low in sulfur content may be mined directly from the ground. Alternatively, the sulfur content of coal fired in the boiler may be lowered first by cleaning the coal or blending coals obtained from several sources. However, burning low-sulfur coal may not be a technically feasible or economically practical SO₂ control alternative for all boilers. In some cases, a coal with the required sulfur content to meet the applicable standard may not be available or cannot be fired satisfactorily in a given boiler unit design. Even if such a coal is available, use of the low-sulfur coal that must be transported long distances from the mine may not be cost-competitive with burning higher sulfur coal supplied by closer mines and using a post-combustion control device.

Table II-3 Nationwide distribution of existing SO₂ emissions controls used for coal-fired electric utility boilers for the year 1999 as reported in the Part II USEPA ICR data (USEPA, 2001).

SO ₂ Control Type	Abbreviation Code	Phase II USEPA ICR Data		
		Number of Boilers	Percent of Nationwide Total Number of Units	Percent of Nationwide Electricity Generating Capacity
Burn low-sulfur coal (“compliance coal”)	LSC	455	39.9 %	38.2 %
Wet FGD system	FGD	173 (a)	15.2 %	23.8 %
Spray dryer system	SDA	52 (b)	4.6%	3.4 %
Fluidized-bed coal combustion with limestone	FBC	37 (a,c)	3.2%	1.1 %
Dry injection	DI	2	0.2 %	< 0.1 %
No controls reported (d)		421	36.9 %	33.5 %
Nationwide Total		1,140 (e)	100 %	100 %

(a) Includes one FBC boiler unit using a wet FGD system.

(b) Includes three FBC boilers using spray dryer systems.

(c) FBC boilers using no downstream post-combustion SO₂ controls.

(d) Entry in ICR response indicated none or was left blank.

(e) Does not include the three IGCC units.

Various coal cleaning processes may be used to reduce the sulfur content of the coal. A significant portion of the pyritic sulfur minerals mixed with the mined coal can usually be removed by physical gravity separation or surface property (flotation) methods. However, physical coal cleaning methods are not effective for removing the organic sulfur bound in coal. Another method of reducing the overall sulfur content of the coal burned in a given boiler unit is to blend coals with different sulfur contents to meet a desired or target sulfur level.

Wet FGD Systems

The SO₂ in flue gas can be removed by reacting the sulfur compounds with a solution of water and an alkaline chemical to form insoluble salts that are removed in the scrubber effluent. These processes are called “wet FGD systems” in this report. Most wet FGD systems for control of SO₂ emissions from coal-fired electric utility boilers are based on using either limestone or lime as the alkaline source. At some of these facilities, fly ash is mixed with the limestone or lime. Several other scrubber system designs (e.g., sodium carbonate, magnesium oxide, dual alkali) are also used by a small percentage of the total number of boilers.

The basic wet limestone scrubbing process is simple and is the type most widely used for control of SO₂ emissions from coal-fired electric utility boilers. Limestone sorbent is inexpensive and generally available throughout the United States. In a wet limestone scrubber, the flue gas containing SO₂ is brought into contact with limestone/water slurry. The SO₂ is absorbed into the slurry and reacts with limestone to form an insoluble sludge. The sludge, mostly calcium sulfite hemihydrate and gypsum, is disposed of in a pond specifically constructed for the purpose or is recovered as a salable byproduct.

The wet lime scrubber operates in a similar manner to the wet limestone scrubber. In a wet lime scrubber, flue gas containing SO₂ is contacted with hydrated lime/water slurry; the SO₂ is absorbed into the slurry and reacts with hydrated lime to form an insoluble sludge. The hydrated lime provides greater alkalinity (higher pH) and reactivity than limestone. However, lime-scrubbing processes require appropriate disposal of large quantities of waste sludge.

The SO₂ removal efficiencies of existing wet limestone scrubbers range from 31 to 97 percent, with an average of 78 percent. The SO₂ removal efficiencies of existing wet lime scrubbers range from 30 to 95 percent. For both types of wet scrubbers, operating parameters affecting SO₂ removal efficiency include liquid-to-gas ratio, pH of the scrubbing medium, and the ratio of calcium sorbent to SO₂. Periodic maintenance is needed because of scaling, erosion, and plugging problems. Recent advancements include the use of additives or design changes to promote SO₂ absorption or to reduce scaling and precipitation problems.

Spray Dryer Absorber

A spray dryer absorber (sometimes referred to as wet-dry or semi-dry scrubbers) operates by the same principle as wet lime scrubbing, except that the flue gas is contacted with a fine mist of lime slurry instead of a bulk liquid (as in wet scrubbing). For the spray dryer absorber process, the combustion gas containing SO₂ is contacted with fine spray droplets of hydrated lime slurry in a spray dryer vessel. This vessel is located downstream of the air heater outlet where the gas temperatures are in the range of 120 to 180 °C (250 to 350 °F). The SO₂ is absorbed in the slurry and reacts with the hydrated lime reagent to form solid calcium sulfite and calcium sulfate as in a wet lime scrubber. The water is evaporated by the hot flue gas and forms dry, solid particles containing the reacted sulfur. These particles are entrained in the flue gas,

along with fly ash, and are collected in a PM collection device. Most of the SO₂ removal occurs in the spray dryer vessel itself, although some additional SO₂ capture has also been observed in downstream particulate collection devices, especially fabric filters. This process produces dry reaction waste products for easy disposal.

The primary operating parameters affecting SO₂ removal are the calcium-reagent-to-sulfur stoichiometric ratio and the approach to saturation in the spray dryer. To increase overall sorbent use, the solids collected in the spray dryer and the PM collection device may be recycled. The SO₂ removal efficiencies of existing lime spray dryer systems range from 60 to 95 percent.

Dry Injection

For the dry injection process, dry powdered lime (or another suitable sorbent) is directly injected into the ductwork upstream of a PM control device. Some systems use spray humidification followed by dry injection. This dry process eliminates the slurry production and handling equipment required for wet scrubbers and spray dryers, and produces dry reaction waste products for easier disposal. The SO₂ is adsorbed and reacts with the powdered sorbent. The dry solids are entrained in the combustion gas stream, along with fly ash, and collected by the PM control device. The SO₂ removal efficiencies of existing dry injection systems range from 40 to 60 percent.

Circulating Fluidized-bed Absorber

In the circulating fluidized-bed absorber (CFBA), the flue gas flows upward through a bed of sorbent particles to produce a fluid-like condition in the bed. This condition is obtained by adjusting gas flow rate sufficiently to support the particles, but not carry them out of the system. Characteristics of the bed are high heat and mass transfer, because of high mixing rates, and particle-to-gas contact. These conditions allow the CFBA's bed of sorbent particles to remove a sorbate from the gas stream with high effectiveness. In a CFBA, material is withdrawn from the bed for treatment (such as desorption) then re-injected into the bed. The SO₂ removal efficiencies for CFBA technologies range from 80 to 98 percent, providing a very effective means of control.

NO_x Emission Controls

Control techniques used to reduce NO_x formation include combustion and post-combustion control measures. Combustion measures consist of operating and equipment modifications that reduce the peak temperature and excess air in the furnace. Post-combustion control involves converting the NO_x in the flue gas to molecular nitrogen and water using either a process that requires a catalyst (selective catalytic reduction) or a process that does not use a catalyst (selective noncatalytic reduction).

Table II-4 presents the 1999 nationwide distribution of NO_x controls used for coal-fired electric utility boilers by total number of units and by percentage of nationwide electricity generating capacity. Approximately one-third of the boilers do not use additional NO_x controls. The other two-thirds of the units use additional controls to meet the applicable NO_x standards. The predominant control NO_x strategy is to use one or more combustion control techniques. Post-combustion NO_x reduction technologies (both catalytic and noncatalytic) accounted for

only a small percentage of the NO_x emission controls used in 1999 (approximately three percent of the total units). However, a number of electric utilities have recently retrofitted and are currently actively retrofitting a large number of units with advanced SCR technology to meet the requirements of the federal Title IV acid rain program or the Section 110 Transport SIP call.

Combustion Controls

A variety of combustion control practices can be used including low-NO_x burners (LNBS), overfire air, off-stoichiometric firing, selective or biased burner firing, reburning, and burners-out-of-service. Control of NO_x also can be achieved through staged combustion (also called air staging). With staged combustion, the primary combustion zone is fired with most of the air needed for complete combustion of the coal. The remaining air is introduced into the products of the partial combustion in a secondary combustion zone. Air staging lowers the peak flame temperature, thereby reducing thermal NO_x, and lowering the production of fuel NO_x by reducing the oxygen available for combination with the fuel nitrogen. Staged combustion may be achieved through methods that require modifying equipment or operating conditions so that a fuel-rich condition exists near the burners (e.g., using specially designed low- NO_x burners, selectively removing burners from service, or diverting a portion of the combustion air). In cyclone boilers and some other wet bottom designs, combustion occurs with a molten ash layer and the combustion gases flow to the main furnace; this design precludes the use of low NO_x burners and air staging. Low-NO_x burners may be used to lower NO_x emissions by about 25 to 55 percent. Use of overfire air (OFA) as a single NO_x control technique reduces NO_x by 15 to 50 percent. When OFA is combined with low- NO_x burners, reductions of up to 60 percent may result. The actual NO_x reduction achieved with a given combustion control technique may vary from boiler to boiler.

Table II-4 Nationwide distribution of existing NO_x emissions controls used for coal-fired electric utility boilers for the year 1999 as reported in the Part II USEPA ICR data (USEPA, 2001).

NO _x Control Type	Abbreviation Code	Phase II USEPA ICR Data		
		Nationwide Number of Boilers	Nationwide Percentage of Boilers	Percent of Nationwide Electricity Generating Capacity
Combustion controls - low- NO _x burners	CC-LNB	404	35.4 %	43.0 %
Combustion controls - low- NO _x burners + overfire air	CC-LNB/OFA	84	7.4 %	10.4 %
Combustion controls - overfire air	CC-OFA	79	6.9 %	10.6 %
Other combustion controls (a)	CC	83	7.3 %	5.6 %
Selective noncatalytic reduction	SNCR	32	2.8 %	0.6 %
Selective catalytic reduction	SCR	6	0.5 %	1.3 %
No controls reported (b)		452	39.7%	28.5 %
Nationwide Total		1,140 (c)	100 %	100 %

(a) Combustion controls other than low-NO_x burners or overfire air. The controls include burners-out-of service, flue gas recirculation, off-stoichiometric firing, and fluidized-bed combustion.

(b) Entry in ICR response indicated “none,” “not applicable,” or was left blank.

(c) Does not include the three IGCC units.

Just as the combustion air to the primary combustion zone can be reduced, part of the fuel may be diverted to create a secondary flame with fuel-rich conditions downstream of the primary combustion zone. This combustion technique is termed reburning and involves injecting 10 to 20 percent of the fuel after the primary combustion zone and completing the combustion with overfire air. The fuel injected downstream may not necessarily be the same as that used in the primary combustion zone. In most applications of reburning, the primary fuel is coal and the reburn fuel is natural gas (methane), and the technology is known as “gas reburn.”

Other ways to reduce NO_x formation by reducing peak flame temperature include using flue gas recirculation (FGR), reducing boiler load, injecting steam or water into the primary combustion zone, and increasing spacing between burners. By using FGR to return part of the flue gas to the primary combustion zone, the flame temperature and the concentration of oxygen in the primary combustion zone are reduced. Increasing the space between burners provides greater heat transfer to heat-absorbing surfaces. Another combustion control technique involves reducing the boiler load. In this case, the formation of thermal NO_x generally decreases directly with decreases in heat release rate; however, reducing the load may cause poor air and fuel mixing and increase CO and soot emissions.

Selective Catalytic Reduction

The selective catalytic reduction (SCR) process uses a catalyst with ammonia gas (NH₃) to reduce the NO and NO₂ in the flue gas to molecular nitrogen and water. The ammonia gas is diluted with air or steam, and this mixture is injected into the flue gas upstream of a metal catalyst bed (composed of vanadium, titanium, platinum, or zeolite). In the reactor, the reduction reactions occur at the catalyst surface. Typically some ammonia exits the catalyst, on the order of 1-5 ppm in the flue gas; this is called “ammonia slip”. The SCR catalyst bed reactor is usually located between the economizer outlet and air heater inlet, where temperatures range from 230 to 400 °C (450 to 750 °F). The catalyst modules take up a considerable amount of space; in addition ductwork must be added for the ammonia injection section. There is not always room in an existing boiler to retrofit an SCR system. As a consequence, fan capacity may have to be increased, owing to the incremental pressure drop from the SCR and associated ductwork. In some cases, the boiler must be modified to increase the economizer exit temperature to the minimum and/or the air preheater must be modified. Installation of an SCR on a boiler is site-specific and this results in a range of capital costs for SCR systems on boilers.

SCR catalysts in coal- and oil-fired boilers oxidize a small fraction of the SO₂ in the flue gas to produce SO₃. The SO₃ in the flue gas from an SCR may only be on the order of 10 ppm (depending on the sulfur-content of the fuel), but it can have impacts on the downstream equipment and emissions. The combination of ammonia slip and increased SO₃ can form deposits of ammonium bisulfate in the air preheater. SO can condense in the flue gas in the form of a fine aerosol of sulfuric acid, which can cause a visible plume, the so-called “blue plume”.

Selective Noncatalytic Reduction

The selective noncatalytic reduction (SNCR) process is based on the same basic chemistry of reducing the NO and NO₂ in the flue gas to molecular nitrogen and water but does not require the use of a catalyst to prompt these reactions. Instead, the reducing agent is injected into the flue gas stream at a point where the flue gas temperature is within a very specific

temperature range. Currently, two SNCR processes are commercially available: the THERMAL DeNO_x and the NO_xOUT (USEPA, 1998). The THERMAL DeNO_x uses ammonia gas as the reagent and requires the gas be injected where the flue gas temperature is in the range of 870 to 1090 °C (1,600 to 2,000 °F). Consequently, the ammonia gas is injected at a location upstream of the economizer. However, if the ammonia is injected above 1,090 °C (2,000 °F), the ammonia will oxidize and will result in the formation of excess NO_x emissions. Once the flue gas temperature drops below the optimum temperature range, the effectiveness of the process drops significantly. By adding hydrogen gas or other chemical enhancers, the reduction reactions can be sustained to temperatures down to approximately 700 °C (1,300 °F). The NO_xOUT is a similar process but uses an aqueous urea solution as the reagent in place of ammonia.

Using nitrogen-based reagents requires operators of SNCR systems to closely monitor and control the rate of reagent injection. If injection rates are too high, NO_x emissions may increase, and stack emissions of ammonia in the range of 10 to 50 ppm may also result. A portion (usually around 5 percent) of the NO reduction by SNCR systems results from transformation of NO to N₂O, which is a global warming gas.

Particulate Matter Emission Controls

Four types of control devices are used to collect PM emissions from coal-fired electric utility boilers: electrostatic precipitators, fabric filters, mechanical collectors, and particle scrubbers. Table II-5 presents the 1999 nationwide distribution of PM controls on coal-fired electric utility boilers by total number of units and by percentage of nationwide electricity generating capacity. Electrostatic precipitators are the predominant control type used on coal-fired electric utility boilers both in terms of number of units (84 percent) and total generating capacity (87 percent). The second most common control device type used is a fabric filter. Fabric filters are used on about 14 percent of the coal-fired electric utility boilers. Particle scrubbers are used on approximately three percent of the boilers. The least used control device type is a mechanical collector. Less than one percent of the coal-fired electric utility boilers use this type of control device as the sole PM control. Other boilers equipped with a mechanical collector use this control device in combination with one of the other PM control device types.

Electrostatic Precipitators

Electrostatic precipitator (ESP) control devices have been used to control PM emissions for over 80 years. These devices can be designed to achieve high PM collection efficiencies (greater than 99 percent), but at the cost of increased unit size. An ESP operates by imparting an electrical charge to incoming particles, and then attracting the particles to oppositely charged metal plates for collection. Periodically, the particles collected on the plates are dislodged in sheets or agglomerates (by rapping the plates) and fall into a collection hopper. The dust collected in the ESP hopper is a solid waste that must be disposed of.

Table II-5 Nationwide distribution of existing PM emission controls used for coal-fired electric utility boilers for the year 1999 (USEPA, 2001).

PM Control Type	Abbreviation Code	Phase II USEPA ICR Data		
		Number of Boilers	Percent of Nationwide Total Number of Units	Percent of Nationwide Electricity Generating Capacity
Electrostatic precipitator (Cold-side)	CS- ESP	822 (a)	72.1 %	74.7 %
Electrostatic precipitator (Hot-side)	HS-ESP	122	10.8 %	11.3 %
Fabric filter	FF	155 (b)	13.6 %	9.4 %
Particle scrubber	PS	23 (c)	2.0%	3.0 %
Mechanical collector (d)	MC	5	0.4 %	0.2 %
Multiple control device combinations (e)		13	1.1 %	1.4 %
Nationwide Total		1,140 (f)	100 %	100 %

- (a) Includes 10 boilers with cold-side ESP in combination with upstream mechanical collector.
- (b) Includes eight boilers with baghouse in combination with upstream mechanical collector.
- (c) Includes two boilers with particle scrubber in combination with upstream mechanical collector.
- (d) Boilers using mechanical collector as only PM control device.
- (e) Boilers using a combination of two or more different control device types other than mechanical collectors. Includes two boilers that use a hot-side ESP in series with a cold-side ESP.
- (f) Does not include the three IGCC units.

The effectiveness of particle capture in an ESP depends largely on the electrical resistance of the particles being collected. An optimum value exists for a given ash. Above and below this value, particles become less effectively charged and collected. Table II-6 presents the PM collection efficiency of an ESP compared with the other control device types. Coal that contains a moderate to high amount of sulfur (more than approximately three percent) produces an easily collected fly ash. Low-sulfur coal produces a high-resistivity fly ash that is more difficult to collect. Resistivity of the fly ash can be changed by operating the boiler at a different temperature or by conditioning the particles upstream of the ESP with sulfur trioxide, sulfuric acid, water, sodium, or ammonia. In addition, collection efficiency is not uniform for all particle sizes. For coal fly ash, particles larger than about 1 to 8 μm and smaller than about 0.3 μm (as opposed to total PM) are typically collected with efficiencies from 95 to 99.9 percent. Particles near the 0.3 μm size are in a poor charging region that reduces collection efficiency to 80 to 95 percent.

An ESP can be used at one of two locations in a coal-fired electric utility boiler system. For many years, every ESP was installed downstream of the air heater where the temperature of the flue gas is between 130 and 180 °C (270 and 350 °F). An ESP installed at this location is referred to as a "cold-side" ESP. However, to meet SO₂ emission requirements, many electric utilities switched to burning low-sulfur coal (discussed in Section 2.3.2 under SO₂ controls). These coals have higher electrical ash resistivities, making the fly ash more difficult to capture downstream of the air heater. Therefore, to take advantage of the lower fly-ash resistivities at higher temperatures, some ESPs are installed upstream of the air heater, where the temperature of the flue gas is in the range of 315 to 400 °C (600 to 750 °F). An ESP installed upstream of the air heater is referred to as a "hot-side" ESP. (Buonicore and Davis, 1992; USEPA, 1998).

Fabric Filters

Fabric filters (FF) have been used for fly ash control from coal-fired electric utility boilers for about 30 years. This type of control device collects fly ash in the combustion gas stream by passing the gases through a porous fabric material. The buildup of solid particles on the fabric surface forms a thin, porous layer of solids or a filter, which further acts as a filtration medium. Gases pass through this cake/fabric filter, but the fly ash is trapped on the cake surface. The fabric material used is typically fabricated in the shape of long, cylindrical bags. Hence, fabric filters also are frequently referred to as "baghouses."

Table II-6 Comparison of PM collection efficiencies for different PM control device types (Buonicore and Davis, 1992).

PM Control Type	Representative PM Mass Collection Efficiency Range	
	Total PM	PM less than 0.3 μm
Electrostatic precipitator (Cold-side)	99 to 99.7 %	80 to 95 %
Electrostatic precipitator (Hot-side)	99 to 99.7 %	80 to 95 %
Fabric filter	99 to 99.9 %	99 to 99.8%
Particle scrubber	95 to 99 %	30 to 85 %
Mechanical collector	70 to 90 %	0 to 15 %

Gas flow through a FF becomes excessively restricted if the filter cake on the bags becomes too thick. Therefore, the dust collected on the bags must be removed periodically. The type of mechanism used to remove the filter cake classifies FF design types. Depending on the FF design type, the dust particles will be collected either on the inside or outside of the bag. For designs in which the dust is collected on the inside of the bags, the dust is removed by either mechanically shaking the bag (called a "shaker type" FF) or by blowing air through the bag from the opposite side (called a "reverse-air" FF). An alternate design mounts the bags over internal frame structures, called "cages" to allow collection of the dust on the outside of the bags. A pulsed jet of compressed air is used to cause a sudden stretching then contraction of the bag fabric dislodging the filter cake from the bag. This design is referred to as a "pulse-jet" FF. The dislodged dust particles fall into a hopper at the bottom of the baghouse. The dust collected in the hopper is a solid waste that must be disposed of.

An FF must be designed and operated carefully to ensure that the bags inside the collector are not damaged or destroyed by adverse operating conditions. The fabric material must be compatible with the gas stream temperatures and chemical composition. Because of the temperature limitations of the available bag fabrics, location of an FF for use in a coal-fired electric utility boiler is restricted to downstream of the air heater. In general, fabric filtration is the best commercially available PM control technology for high-efficiency collection of small particles.

Electrostatic stimulation of fabric filtration (ESFF) involves a modified fabric filter that uses electrostatic charging of incoming dust particles to increase collection efficiency and reduce pressure drop compared to fabric filters without charging. Filter bags are specially made to include wires or conductive threads, which produce an electrical field parallel to the fabric surface. Conductors can also be placed as a single wire in the center of the bag. When the bags are mounted in the baghouse, the conductors are attached to a wiring harness that supplies electricity. As particles enter the field and are charged, they form a porous mass or cake of agglomerates at the fabric surface. Greater porosity of the cake reduces pressure drop, while the agglomeration increases efficiency of small particle collection. Cleaning is required less frequently, resulting in longer bag life. For felted or nonwoven bags, the field promotes collection on the outer surface of the fabric, which also promotes longer bag life. Filtration velocity can be increased so that less fabric area is required in the baghouse. The amount of reduction is based on an economic balance among desired performance, capital cost, and operating costs. A number of variations exist on the ESFF idea of combining particle charging with fabric filtration. (Buonicore and Davis, 1992; Turner and McKenna, 1989).

Particle Scrubbers and Mechanical Collectors

Particle scrubbers are generally much less efficient than ESPs and baghouses (especially in collecting finer fraction of PM). For this reason and because they entail higher operating costs associated with achieving high collection efficiency, they are not widely used in the industry. Similarly, mechanical collectors have the least collection efficiency and are hardly used in the industry. These two methods are not discussed further in this report. (Buonicore and Davis, 1992).

2.3.3. Emission Control Configurations for Coal-fired Electric Utility Boilers

Table II-7 presents the 1999 nationwide distribution of post-combustion control device configurations used for coal-fired electric utility boilers. For approximately 70 percent of the boilers, the only control device used downstream of the furnace is an ESP. If the unit is subject to SO₂ and/or NO_x emission limit standards, these units do burn low-sulfur coals to meet the SO₂ emission limit and use some type of NO_x combustion controls to meet the NO_x emission limit. Approximately 25 percent of the boilers use some combination of post-combustion control devices. The most common configuration used is an ESP with a downstream wet scrubber for SO₂ control. Less than 2 percent of the units used a combination of PM, SO₂, and NO_x post-combustion control devices.

It is important to note that, for the case of PM, the data on PM control as shown for the year 1999 should not have changed in any significant way. However, for SO₂, the requirements of Phase II (starting in the Year 2000) of the Title IV (acid rain provisions) of the 1990 CAAA, should have resulted in some boilers either switching to low-sulfur coal or the application of wet or dry scrubbers. It appears that the SO₂ scrubber retrofit activity in the U.S. has been rather insignificant since 1999. The most active retrofits have involved the application of SCR, SNCR, and gas reburn (in conjunction with low-NO_x burners where appropriate) to significantly reduce NO_x emissions in the eastern U.S. These reductions, however, are only for ozone season (May 1 to September 30) since the NO_x Transport SIP call applies to ozone season. As of 2003, more than 50 applications of SCRs, SNCRs, or gas reburn have either been completed or are under construction.

Table II-7 Nationwide distribution of post-combustion emission control configurations used for coal fired electric utility boilers for the year 1999 as reported in the Part II USEPA ICR data (USEPA, 2001).

Post-combustion Control Strategy	Post-Combustion Emission Control Device Configuration									Phase II USEPA ICR Data	
	PM control				SO ₂ control			NO _x control			
	E S P	F F	P S	M C	W S	S D A	D I	S C R	S N C R	Number of boilers	Percent of nationwide total number
Post-combustion PM controls only	?									791	69.4%
		?								80	7.0%
	?	?								6	0.5 %
			?							5	0.4 %
	?		?							4	0.4 %
				?						2	0.2 %
	?									2 (a)	0.2 %
Post-combustion PM controls and SO ₂ controls	?				?					133	11.7 %
		?				?				38	3.3%
			?		?					18	1.6 %
		?			?					13	1.1 %
	?					?				4	0.4 %
				?	?					3	0.2 %
	?						?			2	0.2 %
	?	?			?					1	0.1 %
Post-combustion PM controls and NO _x controls		?							?	12	1.0 %
	?								?	11	0.9 %
	?							?		1	0.1 %
Post-combustion PM controls, SO ₂ controls, and NO _x controls		?				?			?	6	0.5 %
		?				?		?		4	0.4 %
		?			?				?	2	0.2%
	?				?			?		1	0.1 %
	?				?				?	1	0.1 %
Total										1,140 (b)	100 %

(a) Units using hot-side ESP in series with a cold-side ESP. Counted as a "multiple control device combination" in Table II-5

(b) Does not include the three IGCC units.

2.4. Costs and Availability of Technology

The technologies to control three of the precursors of regional haze are commercially available. Since EGUs are the most significant stationary source of SO₂, NO_x, and PM, they have been subject to extensive federal and state regulations to control all three pollutants. The technical feasibility of control technologies has been successfully proven for a large number of small (say, 100 MW) to very large boilers (over 1,000 MW) using different types of coal used. Over the last few years, a large amount of cost data have also become available that clearly indicate that many technologies provide substantial and extremely cost effective reductions.

2.4.1. Detailed Capital Costs, Operating and Maintenance Costs, and Cost Effectiveness

Cost of Controlling SO₂ Emissions

Both wet and dry scrubbers are in wide commercial use in the U.S. The capital costs for new or retrofit wet or dry scrubbers are high when compared to the capital costs for NO_x and PM controls. The recent capital costs range from \$180/kW for large units (larger than 600 MW) to as high as \$350 for small units (200 to 300 MW). However, the last few years has seen a general trend of declining capital costs due to vendor competition and technology maturation. The cost effectiveness (in dollars per ton) is very attractive, since these devices remove a very large amount of SO₂ (driven by high sulfur content of coal burned). The typical cost effectiveness is in the range of 200 to 500 dollars per ton of SO₂ removed though higher values are obtained for small units operating at low capacity factors and burning low-sulfur coal. The cost effectiveness is determined mostly by the baseline pre-controlled SO₂ emission rate (or sulfur content of fuel), size and capacity factor of the unit, as well as the capital cost of FGDs (that generally ranges from \$150 to \$200/kW).

Cost of Controlling NO_x

A representative summary of range of costs associated with various technologies for NO_x control is provided below.

Gas Reburn

In general, the capital costs range from \$15/kW to \$30/kW for gas reburn and \$30/kW to \$60/kW when using coal as the reburn fuel. Operating costs are mainly driven by fuel cost differential (certainly gas vs. coal). For other fuels (e.g. coal/orimulsion reburning), fuel preparation costs become more important (micronization, atomization) as there is little or no fuel cost differential. The cost in dollars per ton of NO_x removed is in the range of 500 to 2000 dollars.

Retrofit schedules are directly related to the scope of the retrofit requirements. In most cases, 3-6 weeks are adequate for a reburn retrofit.

Low-NO_x Burners

In general, the capital costs for burners range from \$10,000 to 50,000 per burner plus installation. The lower end of this range applies when existing burners are modified instead of replaced to achieve lower NO_x. Operating costs are negligible unless increased unburned carbon results in lost revenues from ash sales. An outage is generally required when implementing this technology, but coal-flow sensors and adjustable orifices are best installed when a mill is out of service. Low-NO_x Burners provide moderate NO_x reductions in the range of 30 to 60% at moderate cost (\$200 to 500 per ton of NO_x removed).

Overfire Air (OFA)

OFA technologies have little or no impact on operating costs (other than the potential for an increase in unburned carbon - efficiency loss -, and the resulting impact on ash disposal options). Retrofit costs are site-specific. As such, the economics of these technologies are driven by capital/retrofit costs which typically range from \$5-\$10/kW, with the lower range reflecting easier application whereas the higher costs are typically associated with more difficult and involved retrofits. The cost effectiveness is in the range of \$250 to 600 per ton of NO_x removed.

From a schedule standpoint, OFA retrofit projects can require outages of 3 – 6 weeks, depending on factors such as scope of work, integration with other plant outage requirements, etc.

SCR

Capital costs for retrofit SCR systems to coal-fired power generation sources are specific to the individual site, but have been documented to be within the range of \$70/kW to about \$190/kW. The lower end of this range applies to retrofits with nominal difficulty. The high end of the range would typically be associated with retrofits having significantly impeded construction access, extensive relocations, and difficult ductwork transitions.

Capital costs for retrofit SCR systems on oil and gas-fired boilers are substantially lower (about half to one third) than costs of coal-fired boiler retrofits. Lower volumes of catalyst are required for gas-fired boilers because of the lack of ash and catalysts poisons like arsenic in the flue gas. Capital costs for oil-fired retrofits are intermediate between coal- and gas-fired retrofits. Oil combustion produces some particulate matter, which necessitates larger SCR catalyst volume as compared to that for natural gas.

Operating costs are mainly driven by cost of reagent, energy penalty (pressure loss, ammonia vaporization), catalyst replacement and dedicated O and M costs. SCR technology offers very high NO_x reductions (from 90 to 95%) and cost effectiveness (in the range of \$1,000 to 1500 per ton of NO_x removed).

SNCR

The capital costs for SNCR application are low making it an attractive option for moderate NO_x reductions (25 to 50%). Capital costs range from \$10 to \$20/kW for power generation boilers.

Operating costs are driven primarily by the consumption of the chemical reagent – usually urea for SNCR - which in turn is dependent upon the efficiency of the control equipment as well as the initial NO_x level and the desired percent reduction. These are typically in the range of \$500-\$700/ton of NO_x.

An additional consideration important in the overall operating costs is the potential contamination of fly ash by ammonia making it potentially unsalable.

Cost of Controlling PM

The costs associated with controlling PM from EGUs generally do not scale on the size of the unit but on the volume of flue gases processed by the control devices (ESPs or fabric filters). The representative costs are provided below.

ESPs

The following values represent typical costs for application of ESPs to units handling a range of flue gas rates (these numbers reflect unit sizes ranging from utility-size units up to about 2,000,000 ACFM to smaller process down to about 10,000 ACFM):

- Capital: \$15 - \$40/ACFM
- Fixed O&M: Dry ESP's - \$0.25 - \$0.65/yr-ACFM
Wet ESP's - \$0.15- \$0.50/yr-ACFM
- Variable O&M: Dry ESP's - \$0.45 - \$0.60/yr-ACFM
Wet ESP's - \$0.25 - \$0.50/yr-ACFM

Fabric Filters

Baghouses have been used extensively for many years in different industries. The EGU sector, while predominantly dominated by ESP's, has started to utilize FF's in the last 20 years.

- Capital: Reverse Air Fabric Filter - \$17 - \$40/ACFM
Pulse Jet Fabric Filter - \$12 - \$40/ACFM
- Fixed O&M: Reverse Air Fabric Filter - \$0.35 - \$0.75/yr-ACFM
Pulse Jet Fabric Filter - \$0.50 - \$0.90/yr-ACFM
- Variable O&M: Reverse Air Fabric Filter - \$0.70 - \$0.80/yr-ACFM
Pulse Jet Fabric Filter - \$.90 - \$1.1/yr-ACFM

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3. INDUSTRIAL BOILERS

Industrial boilers are a significant source of emissions among the twenty-six source categories covered under the Regional Haze Rule. Estimates of national emissions for criteria air pollutants prepared by the USEPA (2000) show that industrial boilers contributed approximately 12 percent of the estimated total national SO₂ emissions and 23 percent of total national NO_x emissions in 1998 (the most recent year for which national estimates are available). Industrial boilers also are one of the largest industrial sources of PM emissions, with 16 percent of the national PM₁₀ emissions and 20 percent of the national PM_{2.5} in 1998. Contrast this with the emissions of EGUs for which PM₁₀ and PM_{2.5} emissions were 25 percent and 23 percent of national totals in 1998, respectively. In general, the combustion efficiencies achieved by industrial boilers are lower than those of EGUs, resulting in significant emissions of CO (18 percent of the 1998 emissions) and volatile organic compounds (6 percent of the 1998 emissions) from industrial boilers. Industrial boilers also produced 16 percent of the ammonia emissions in 1998. Ammonia is precursor of secondary PM in the atmosphere.

About 46 percent of the SO₂ emissions from industrial boilers are from coal-fired boilers (see Table III-1). The predominant sources of NO_x emissions from industrial boilers are gas-fired boilers (30 percent) and internal combustion boilers (34 percent); coal-fired boilers were only responsible for 17 percent of NO_x emissions from industrial boilers. Although the emphasis of this Chapter is on coal-fired utility boilers, many technologies described here are also applicable to gas and oil-fired units (for example, SCR and SNCR technologies are equally applicable to coal and natural gas/oil units, generally at much lower capital and operating costs; same is true for wet scrubbers for SO₂ control and ESPs or baghouses for PM control for oil units).

Table III-1 Distribution of emissions from industrial fuel boilers from 1998 National Emissions Inventory (USEPA, 2000)

Fuel/Source	NO _x	SO ₂	PM ₁₀	PM _{2.5}
Coal	17%	46%	31%	16%
Oil	7%	27%	18%	16%
Gas	39%	21%	18%	26%
Other	4%	5%	25%	32%
Internal Combustion	34%	1%	7%	10%

3.1. Description of Boiler Process

Typically, industrial boilers generate steam used for process heating or on-site generation of electricity. Industrial boilers burn a wider variety of fuels than EGUs and there are a larger number of boiler designs in use than in the electric power sector. According to information contained in USEPA's Docket on "National Emission Standards for Hazardous Air Pollutants for Industrial/ Commercial/Institutional Boilers

and Process Heaters” (USEPA, 2004) in 1998 there were 63,767 fossil fuel-fired boilers, 1,100 wood-fired boilers and 998 boilers classified as non-fossil-fuel-fired. The fossil fuels fired were natural gas, distillate oil, residual oil, coal and petroleum coke. The majority (75 to 95 percent) of the boilers firing natural gas, residual oil and distillate oil are fire tube boilers; the rest are water tube boilers. Coal-fired boilers include fluidized bed boilers, stokers, cyclone boilers, and pulverized coal-fired boilers (wall-fired or tangentially fired). Wood-fired boilers include fluidized bed boilers, cyclones, stokers and dutch ovens.

3.2. Review of BART-Eligible Industrial Boilers in the MANE-VU Region

There are 10 facilities with BART-Eligible industrial boilers in the MANE-VU region. Table III-2 contains a list of these sources based on a previous NESCAUM report (2003) and follow-up review by state permitting authorities.⁵

Table III-2 BART-Eligible Facilities in the Industrial Boiler Category

State	Company/Facility	City/Town	Category
Connecticut	SPRAGUE PAPERBOARD INC	Versailles	boilers
Massachusetts	GENERAL ELECTRIC AIR (GE Aircraft Engines)	Lynn	boilers
Massachusetts	TRIGEN BOSTON ENERGY-KNEELAND STATION	Boston	boilers
Massachusetts	SOLUTIA INC. (MONSANTO CO.)	Springfield	boilers
Massachusetts	HARVARD UNIVERSITY CAMBRIDGE	Cambridge	boilers
Maine	International Paper - Bucksport	Bucksport	boilers
Maine	Katadhin - Mill W.	Millinocket	boilers
New Hampshire	Annheuser-Busch	Merrimack	boilers
New Hampshire	Dartmouth College	Hanover	boilers
Rhode Island	BROWN UNIVERSITY	Providence	boilers

3.3. Available Control Technologies

A variety of emission control technologies are employed to meet requirements for sulfur dioxide (SO₂), nitrogen oxides (NO_x), and primary PM emissions, the three major precursors of observed regional haze in the atmosphere. SO₂ and NO_x are mostly converted to ammonium sulfate and ammonium nitrate that are formed by the reactions of precursor gases with ammonia, which is emitted mostly from agricultural and cattle-related activities.

Pollutant emission controls are generally divided into three major types:

⁵ NESCAUM does not believe that there are any BART-eligible sources in the State of Vermont or any of the member Tribes in MANE-VU and thus we have not developed lists for these jurisdictions. In addition, Pennsylvania and the District of Columbia have developed BART-Eligible source lists following their own methodology and any identified sources are contained here and in the final list in Appendix A.

- *Pre-combustion Controls.* Control measures in which fuel substitutions are made or fuel pre-processing is performed to reduce pollutant formation in the combustion unit.
- *Combustion Controls.* Control measures in which operating and equipment modifications are made to reduce the amount of pollutants formed during the combustion process; or in which a material is introduced into the combustion unit along with the fuel to capture the pollutants formed before the combustion gases exit the unit.
- *Post-combustion Controls:* Control measures in which one or more air pollution control devices are used at a point downstream of the furnace combustion zone to remove the pollutants from the post-combustion gases.

3.3.1. Emission Characteristics of Regional Haze Precursors from Industrial Boilers

Nitrogen Oxides

The formation of NO_x is an unfortunate byproduct of the combustion of fossil fuels. Both NO and NO_2 (collectively called NO_x) are formed during fossil fuel combustion by oxidation of molecular nitrogen that is present in the combustion air or nitrogen compounds contained in the fuel. The degree to which this conversion occurs is dependent on many factors including both the combustion process itself and the properties of the particular fuel being burned. This explains why similar boilers firing different fuels or similar fuels burned in different boilers will yield different NO_x emissions. Overall, total NO_x formed during combustion is composed predominantly of NO mixed with small quantities of NO_2 (typically less than 10 percent of the total NO_x formed). However, once NO formed during coal combustion is emitted to the atmosphere, the NO is oxidized to NO_2 .

The NO_x formed during combustion by oxidation of molecular nitrogen (N_2) in the combustion air is referred to as “thermal NO_x .” The oxidation reactions converting N_2 to NO and NO_2 become very rapid once gas temperatures rise above $1,700^\circ\text{C}$ ($3,100^\circ\text{F}$). Formation of thermal NO_x in a boiler is dependent on two conditions occurring simultaneously in the combustion zone: high temperature and an excess of combustion air. A boiler design feature or operating practice that increases the gas temperature above $1,700^\circ\text{C}$, the gas residence time at these temperatures, or the quantity of excess combustion air affects thermal NO_x formation. The formation of NO_x by oxidation of nitrogen compounds contained in the coal is referred to as “fuel NO_x .” The nitrogen content in coal and petcoke ranges from approximately 0.5 to 2 percent; in wood, the nitrogen content is typically 0.1 to 0.2 percent. The amount of nitrogen available in the fuel is relatively small compared with the amount of nitrogen available in the combustion air. However, a significant portion of the fuel nitrogen can be converted to NO in the flame. Local temperature, oxygen concentration and NO concentration affect the conversion of fuel nitrogen to NO and this is exploited in low- NO_x firing systems.

Sulfur Dioxide

SO₂, like NO_x, is a precursor to acid rain and fine particulate matter (PM_{2.5}) and is also an undesirable byproduct of the combustion of sulfur-containing fuels. Coal deposits contain sulfur in amounts ranging from trace quantities to as high as 8 percent or more. Natural gas contains virtually no sulfur. Residual oil can have 1 to 2 percent sulfur by weight, while petroleum coke can have as much as 6 percent sulfur. During combustion, sulfur compounds in the fuel are oxidized to gaseous SO₂ or SO₃. When firing bituminous coal, almost all of the sulfur present in coal is emitted as gaseous sulfur oxides (on average, 98 percent). The more alkaline nature of ash in some sub bituminous coals causes a portion of the sulfur in the coal to react to form various sulfate salts; these salts are emitted as fly ash or retained in the boiler bottom ash. When firing petcoke or residual oil, more of the SO₂ is converted to SO₃ because of the oxidation that is catalyzed by vanadium in the ash. In coal-fired boilers, SO₃ levels are typically 10 ppm or less. With petcoke firing, however, SO₃ levels as high as several hundred ppm have been reported (Fernando,2001). Formation of SO₃ is a concern because the temperature of the particulate control device or scrubber is often below the acid dew point, resulting in nucleation and condensation of ultrafine sulfuric acid particles from the SO₃ present in the gas. These particles can contribute to the fine PM emissions from the stack.

Unlike nitrogen in fossil fuels and wood, almost all of the sulfur in fuel is oxidized to form SO₂. This means that the relationship between sulfur content in the fuel and SO₂ production is much more direct than that between fuel nitrogen and NO_x, and as such, it makes fuel switching (for example higher to lower sulfur coal) directly proportional to reductions in SO₂. Generally, the percentage of sulfur in the fuel that is converted to sulfur oxides during combustion does not vary with the boiler design or operation. The exception to this is the fluidized bed boiler in which limestone is added to the bed. The bed is operated at a sufficiently low temperature (compared to other combustion systems) that sulfur is captured effectively in the bed as calcium sulfate.

Particulate Matter

Primary PM emissions from boilers consist primarily of fly ash. Ash is the unburned carbon and the mineral portion of the fuel. Coals contain 4 to 12 percent ash typically. Other liquid or solid fuels (oil, petroleum coke, wood) contain less than one percent ash. The amount of ash that ultimately exits the boiler unit as fly ash is a complex function of the fuel properties, furnace-firing configuration, and boiler operation. For the dry-bottom, pulverized-coal-fired boilers, approximately 80 percent of the total ash in the as-fired coal exits the boiler as fly ash. Wet-bottom, pulverized-coal-fired boilers emit significantly less fly ash: on the order of 50 percent of the total ash exits the boiler as fly ash. In a cyclone-fired boiler, most of the ash is retained as liquid slag; thus, the quantity of fly ash exiting the boiler is typically 20 to 30 percent of the total ash. However, the high operating temperatures unique to these designs promote ash vaporization and this results in larger fractions of submicron fly ash compared to dry bottom designs. Fluidized-bed combustors emit high levels of fly ash since the coal is

fired in suspension and the ash is present in dry form. Spreader-stoker-fired boilers can also emit high levels of fly ash. However, overfeed and underfeed stokers emit less fly ash than spreader stokers, since combustion takes place in a relatively quiescent fuel bed.

In addition to the fly ash, PM emissions from boilers result from reactions of the SO₂ and NO_x compounds as well as unburned carbon particles carried in the flue gas from the boiler. The SO₂ and NO_x compounds are initially in the vapor phase following coal combustion in the furnace chamber but can partially chemically transform in the stack, or near plume, to form fine PM in the form of nitrates, sulfur trioxide (SO₃), and sulfates. Firing configuration and boiler operation can affect the fraction of carbon (from unburned fuel) contained in the fly ash. Combustion efficiencies tend to be lower in industrial boilers than in EGUs. Oil or petcoke combustion results in high amounts of sulfur trioxide as compared to coal combustion because of the high vanadium content of residual oil and petcoke.

NO_x control technologies that inject ammonia or amine-based reagents (like Selective Catalytic Reduction or Selective Non-Catalytic Reduction) produce ammonia, generally with concentrations less than 10 ppm. This ammonia can also form fine particulate in the stack, if it persists through the air pollution control devices.

3.3.2. Control Technologies used for Industrial Boilers

Application Status

According to the 1998 survey of industrial boilers by USEPA (2004), only 2 percent of gas-fired boilers and 3 percent of oil-fired boilers had any kind of air pollution control device. More coal-fired boilers had air pollution control devices: 47 percent had some control device and these were largely PM controls.

For PM controls, ESPs were used on 12 percent of the coal-fired boiler units in 1998, fabric filters or baghouses were used on 10 percent of the boiler units, mechanical collectors were used on 21 percent of the units, and particulate scrubbers were only used on 2 percent of the units. 66 percent of wood-fired boilers used mechanical collectors for PM control, while 10 percent used PM scrubbers and another 10 percent used ESPs.

Post-combustion SO₂ control was used by less than one percent of industrial boilers in 1998, with the exception of boilers firing petcoke: 2 percent of boilers firing petroleum coke had acid scrubbers. A small percentage of industrial boilers had combustion controls in place in 1998, although since 1998, additional low-NO_x firing systems may have been installed.

SO₂ Reduction Overview

Almost all SO₂ emission control technologies fall in the category of reducing SO₂ after its formation, as opposed to minimizing its formation during combustion. The exception to the nearly universal use of post-combustion controls is found in fluidized bed boilers, in which limestone is added to the fluidized bed combustion. Typically 90

percent of the sulfur can be captured in a coal-fired fluidized bed using limestone with Ca/S molar ratios of 2 to 2.5, depending on the sulfur content of the fuel, the reactivity of the limestone and the operation of the combustor.

Post-combustion SO₂ control is accomplished by reacting the SO₂ in the gas with a reagent (usually calcium- or sodium-based) and removing the resulting product (a sulfate/sulfite) for disposal or commercial use depending on the technology used. SO₂ reduction technologies are commonly referred to as Flue Gas Desulfurization (FGD) and/or "Scrubbers" and are usually described in terms of the process conditions (wet versus dry), byproduct utilization (throwaway versus saleable) and reagent utilization (once-through versus regenerable).

Within each technology category, multiple variations are possible and typically involve the type and preparation of the reagent, the temperature of the reaction (for dry processes), the use of enhancing additives, etc. Because these variations mostly involve complex process chemistry, but are fundamentally similar, this summary focuses on the major categories of SO₂ control technologies, their applicability, performance and cost.

Pre-Combustion Control

A coal with sufficiently low sulfur content that when burned in the boiler meets the applicable SO₂ emission standards without the use of additional controls is sometimes referred to as "compliance coal." Coals naturally low in sulfur content may be mined directly from the ground. Alternatively, the sulfur content of coal fired in the boiler may be lowered first by cleaning the coal or blending coals obtained from several sources. However, burning low-sulfur coal may not be a technically feasible or economically practical SO₂ control alternative for all boilers. In some cases, a coal with the required sulfur content to meet the applicable standard may not be available or cannot be fired satisfactorily in a given boiler unit design. Even if such a coal is available, use of the low-sulfur coal that must be transported long distances from the mine may not be cost-competitive with burning higher sulfur coal supplied by closer mines and using a post-combustion control device.

Various coal cleaning processes may be used to reduce the sulfur content of the coal. A significant portion of the pyritic sulfur minerals mixed with the mined coal can usually be removed by physical gravity separation or surface property (flotation) methods. However, physical coal cleaning methods are not effective for removing the organic sulfur bound in coal. Another method of reducing the overall sulfur content of the coal burned in a given boiler unit is to blend coals with different sulfur contents to meet a desired or target sulfur level.

In-Process Controls

Fluidized bed boilers generally operate at lower temperatures than other combustion systems, 800 to 870°C (1500 to 1600°F). The lower temperatures allow the use of limestone or dolomite to be added to the bed to capture sulfur. Limestone (CaCO₃) is converted to CaO at approximately 800°C (1500°F). SO₂ released from the

fuel reacts with CaO to form CaSO₄, which is thermodynamically stable at bed temperatures. By recycling some of the solids leaving the bed, which contain unsulfated calcium, 90 percent removal of SO₂ can be achieved with Ca/S molar ratios of 2 to 2.5 in circulating fluidized beds. Higher Ca/S ratios are required in bubbling beds. In either case, the sorbent is removed with the ash from the bed and sent to disposal.

Post-Combustion Controls

Wet Processes

Wet FGD "scrubbers" date back to the 1960s with commercial applications in Japan and the U.S. in the early 1970s. They represent the predominant SO₂ control technology in use today with over 80% of the controlled capacity in the world and the U.S.

In a wet scrubber, the SO₂-containing flue gas passes through a vessel or tower where it contacts an alkaline slurry, usually in a counterflow arrangement. The intensive contact between the gas and the liquid droplets ensures rapid and effective reactions that can yield greater than 90 percent SO₂ capture. Currently, advanced scrubber designs have eliminated many of the early problems, primarily related to reliability, but have also demonstrated very high SO₂ reduction capabilities with some units providing over 95 percent control.

Variations of the basic technology, in addition to equipment improvements made over the years, include reagent and byproduct differences. Limestone, lime, sodium carbonate and even seawater-based processes are commercial. Limestone is by far the most widely used with commercial-grade gypsum (wallboard quality) being produced in the so-called Limestone Forced Oxidation (LSFO) process. The use of other reagents, as mentioned, is driven by site-specific criteria, such as local reagent availability, economics, efficiency targets, etc.

Dry Processes

Dry processes include spray dryer absorbers (SDA) and Dry Sorbent Injection (DSI) technologies. SDA refers to a configuration where the reaction between SO₂ and the sorbent takes place in a dedicated reactor or scrubber hence the common reference to "dry scrubber"; conversely, DSI uses the existing boiler/duct system as the "reactor" and several configurations are possible based on the temperature window desired. This can occur at furnace (~2200°F), economizer (800-900°F) or duct temperatures (~250°F). Dry processes are more compatible with low to medium sulfur coals due to limitations in reaction rates and sorbent handling (e.g., atomization). Therefore, high-sulfur applications are not likely. In addition, another common feature among them is the need for particulate control downstream of the sorbent injection. Usually this is accomplished through the use of fabric filters (baghouses) which are, not only efficient collectors of particulates, but also provide additional SO₂ removal as the flue gas passes through unreacted sorbent collected on the filters.

Dry SO₂ controls vary significantly in performance, with SDAs being able to achieve about 80 percent removal rates, whereas the various forms of DSI are capable of 40 to 75 percent efficiencies.

NO_x Reduction Overview

As a result of the complex interactions in the formation of NO_x, an equally large number of approaches to minimize or reduce its emissions into the atmosphere have been and continue to be developed. A relatively simple way of understanding the many technologies available for NO_x emission control is to divide them into two major categories: (1) those that minimize the formation of NO_x during the combustion process (e.g., smaller quantities of NO_x are formed); and (2) those that reduce the amount of NO_x formed during combustion prior to exiting the stack into the atmosphere. In industry "language" it is common to refer to the first approach under the "umbrella" of *Combustion Modifications* whereas technologies in the second category are termed *Post-Combustion Controls*.

Within each of these categories, several technologies and variations of the same technology exist. Finally, combinations of some of these technologies are not only possible but often desirable as they may produce more effective NO_x control than the application of a stand-alone technology.

The following summaries describe the major technologies in each category.

Combustion Modifications

Combustion modifications can vary from simple "tuning" or optimization efforts (similar to a "tune-up" in a car) to the deployment of dedicated technologies such as Low-NO_x Burners (LNB), Overfire Air (OFA) or gas recirculation (GR).

Boiler Tuning or Optimization

Combustion optimization efforts can lead to improvements in NO_x emissions of 5 to 15 percent or even higher in cases where a unit may be badly "de-tuned." It is important to remember that optimization results are truly a function of the "pre-optimization" condition of the power plant or unit (just as the improvement in a car from a "tune-up" depends on how "bad" it was running prior to it), and as such have limited opportunity for drastic emission reductions.

Recent development of "intelligent controls" - software-based systems that "learn" to operate a unit and then maintain its performance during normal operation, are expected help in keeping plants well-tuned, as they gain acceptance and become common features in combustion control systems.

Low-NO_x Burners and Overfire Air

LNBs and OFA represent practical approaches to minimizing the formation of NO_x during combustion. Simply, this is accomplished by "controlling" the quantities and the way in which fuel and air are introduced and mixed in the boiler (usually referred to as "fuel or air staging").

These technologies are the most prevalent in the power industry at present. For example, plants that have had to comply with Title IV of the CAAA of 1992 have largely used these technologies for compliance. Competing manufacturers have proprietary designs, geared towards application in different boiler types, as well as reflecting their own design philosophies. LNBs and OFA, which can be used separately or as a system, are capable of NO_x reductions of 40 to 60 percent from uncontrolled levels. Again, the type of boiler (e.g., dry versus wet-bottom, wall- versus tangential-fired, NSPS versus pre-NSPS) and the type of fuel (e.g., bituminous versus sub-bituminous) will influence the actual performance achieved.

Furthermore, all combustion modification approaches face a common challenge: that of "striking a balance" between NO_x reduction and fuel efficiency. The concern is exemplified by the typically higher carbon levels in the fly ash, which reflect lower efficiency (more fuel needed for the same electrical output), but also the contamination of the fly ash itself possibly making it unsuitable for reutilization (e.g., cement industry).

LNBs/OFA have little or no impact on operating costs (other than by the potential for the above-mentioned efficiency loss).

From a schedule standpoint, LNB/OFA retrofit projects have "lead" times of 10 to 14 weeks and can require outages of 6 to 10 weeks, depending on factors such as scope of work, integration with other plant outage requirements, etc.

Post-Combustion Controls

Readily available post-combustion NO_x controls are limited to Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR). They are fundamentally similar, in that both use an ammonia-containing reagent to react with the NO_x produced in the boiler, and convert it to harmless nitrogen and water, SNCR accomplishes this at higher temperatures (1700°F-2000°F) in the upper furnace region of the boiler, while SCR operates at lower temperatures (about 700°F) and hence needs a catalyst to produce the desired reaction between ammonia and NO_x.

While this difference between the two technologies may seem minor, it yields significant difference in performance and costs. This is because in the case of SNCR, the reaction occurs in a somewhat uncontrolled fashion (e.g., the existing upper furnace becomes the "makeshift" reactor which is not what it was originally designed to be), while in the SCR case, a dedicated reactor and the reaction-promoting catalyst ensure a highly controlled, efficient reaction. In practice, this means that SNCR has lower capital costs (no need for a reactor/catalyst); higher operating costs (lower efficiency means that more reagent is needed to accomplish a given reduction in NO_x); and finally, has limited NO_x reduction capability (typically 30 to 40 percent with some cases achieving

reductions in the 50 percent range). SCR, on the other hand, offers lower operating costs and the opportunity for very high NO_x reductions (up to 90 percent and higher).

Operating costs are driven primarily by the consumption of the chemical reagent – usually urea for SNCR and ammonia for SCR, - which in turn is dependent upon the efficiency of the process (usually referred to in terms of reagent utilization) as well as the initial NO_x level and the desired percent reduction. Two additional parameters important in the overall operating costs are: (1) the potential contamination of coal fly ash by ammonia making it unsaleable; and (2) the life cycle of the catalyst due to premature “poisoning.”

Selective Catalytic Reduction

The selective catalytic reduction (SCR) process uses a catalyst with ammonia gas (NH₃) to reduce the NO and NO₂ in the flue gas to molecular nitrogen and water. The ammonia gas is diluted with air or steam, and this mixture is injected into the flue gas upstream of a metal catalyst bed (composed of vanadium, titanium, platinum, or zeolite). In the reactor, the reduction reactions occur at the catalyst surface. The SCR catalyst bed reactor is usually located between the economizer outlet and air heater inlet. The catalyst modules take up a considerable amount of space; in addition ductwork must be added for the ammonia injection section. There is not always room in an existing boiler to retrofit an SCR system. As a consequence, fan capacity may have to be increased, owing to the incremental pressure drop from the SCR and associated ductwork. In some cases, the boiler must be modified to increase the economizer exit temperature to the minimum and/or the air preheater must be modified. Installation of an SCR on a boiler is site-specific and this results in a range of capital costs for SCR systems on boilers.

Selective Noncatalytic Reduction

The selective noncatalytic reduction (SNCR) process is based on the same basic chemistry of reducing the NO and NO₂ in the flue gas to molecular nitrogen and water but does not require the use of a catalyst to prompt these reactions. Instead, the reducing agent is injected into the flue gas stream at a point where the flue gas temperature is within a very specific temperature range. A minimum of 0.5 seconds of residence time is required at a temperature of about 1800°F to achieve high (50 to 60 percent) NO_x removal with SNCR. Good dispersion of the reagent in the flue gas is also needed to get good utilization of the reagent and to avoid excessive ammonia slip from the process. The need for a sufficient volume in the boiler at the right temperature window precludes the application of SNCR in all types of industrial boilers.

PM Reduction Overview

Particulate matter is generated by a variety of physical and chemical processes. It is emitted to the atmosphere through combustion, industrial processes, fugitive emissions and natural sources. In combustion processes, the mineral matter (inorganic impurities) is

converted to ash. The particles suspended in the flue gas are known as fly ash. Fly ash constitutes the primary particulate matter, which enters the particulate control device. Particulate matter is in general referred to as "PM", "PM₁₀", "PM_{2.5}" (particulate matter (PM) with an aerodynamic equivalent diameter of 10 microns or less and 2.5 microns or less, respectively).

Quantity and characteristics of the fly ash and particle size distribution depend on the mineral matter content of the fuel, combustion system, and operating conditions. Combustion technique mainly determines the particle size distribution in the fly ash and hence the final particulate emissions. Common combustion systems in pulverized coal firing include dry bottom, wall (front, opposed) and corner (tangential) burners and wet bottom furnaces. In dry bottom boilers, 10 to 20 percent of the ash is discharged as dry, bottom ash. In wet bottom boilers, 50 to 60 percent of the ash is discharged at the bottom of the boiler as slag. Stokers or grate-fired boilers are used to burn coal, wood and waste. The majority of the ash falls through the grate and is discharged as bottom ash. Mineral composition of the coal and the amount of carbon in the fly ash determine the quantity, resistivity and cohesivity of the fly ash.

PM emissions from other point source processes involve similar phenomena where particulate matter is carried with the flue gas, in suspension to the stack. Hence, the general technologies applicable to one source are typically suitable for the others as well. Factors such as type and quantity of PM, characteristics of the process gas (temperature, moisture, other contaminants) have a major influence on the selection and design of the PM control technology.

PM Control Technologies

The following four major types of particulate controls technologies are common for a variety of applications:

Wet scrubbers

Scrubbers work on the principle of rapid mixing and impingement of the particulate with the liquid droplets and subsequent removal with the liquid waste. For particulate controls the "venturi scrubber" is an effective technology whose performance is directly related to the pressure loss across the venturi section of the scrubber. Venturi scrubbers are effective devices for particulate control. However, for higher collecting efficiencies and a wider range of particulate sizes, higher pressures are required. High-energy scrubbers refer to designs operating at pressure losses of 50 to 70 inches of water. Of course, higher pressure translates to higher energy consumption. Performance of scrubbers varies significantly across particle size range with as little as 50 percent capture for small (<2 microns) sizes to 99 percent for larger (>5 microns) sizes, on a mass basis.

Electrostatic Precipitators (ESP)

ESP's operate on the principle of electrophoresis, by imparting a charge to the particulates and collecting them on opposed charged plates. Dry vs. wet refers to whether the gas is water cooled and saturated prior to entering the charged plate area, or is collected dry on the plates. In gases with high moisture content, dry ESPs are not suitable because the wet gas would severely limit the ability to collect the "sticky" particulates from the plates. The wet ESP technology is capable of very high removal efficiencies and is well suited for the wet gas environments. Both types of ESPs are capable of greater than 99 percent removal of particle sizes above 1 micron on a mass basis.

Fabric Filters

These are essentially "giant" vacuum cleaners. As in the case of the dry ESP, Fabric Filters (FFs, sometimes called baghouses) are not well suited for wet gas applications. However FFs are extremely efficient in collecting PM including fine (submicron) size fractions.

Cyclones

Cyclones are devices that separate particulates from the gas stream through aerodynamic/centrifugal forces. However, the technology is only effective in removing larger size particles (greater than about five microns).

3.4. Costs of Technology

3.4.1. NO_x Technologies

A representative summary of range of costs associated with various technologies for NO_x control in industrial boilers is provided in Table III-4, taken from Reference 4. Capital costs and pollutant removal costs (in \$/ton of pollutant removed) are given for three different boiler sizes: 1000, 500, and 100 MMBtu/hr. For each boiler size, the range of costs corresponds to a range of capacities from about low (5 to 14 percent of capacity) to high (86 to 93 percent of capacity). Industrial boilers have a wider range of sizes than EGUs and often operate over a wider range of capacities.

Low-NO_x Burners (LNBs)

The capital costs for coal burners range from \$2,500 to \$5,100 per MMBtu/hr of boiler size. The lower end of this range applies when existing burners are modified instead of replaced to achieve lower NO_x. Operating costs are negligible unless increased unburned carbon results in lost revenues from ash sales. An outage is generally required when implementing this technology, but coal-flow sensors and adjustable orifices are best installed when a mill is out of service. Low-NO_x Burners provide moderate NO_x reductions in the range of 30 to 50 percent at moderate to high cost (\$200 to \$3,000 per ton of NO_x removed). The size of the boiler affects both the capital cost

and the cost per ton. The combination of LNBs and overfire air (OFA), with or without flue gas recirculation (FGR), is more expensive but NO_x reduction is higher, as high as 80 percent for gas-fired boilers. From a schedule standpoint, LBB/OFA retrofit projects can require outages of 3 to 6 weeks, depending on factors such as scope of work, integration with other plant outage requirements, etc.

SNCR

The capital costs for SNCR application are low making it an attractive option for moderate NO_x reductions (about 40 percent). As discussed above, the NO_x reduction that can be achieved will vary from one boiler to another, and depend on the residence time available in the boiler in which the temperatures fall within the window for the SNCR chemistry to take place. Capital costs range from \$2,000 to \$4,000 per MMBtu/hr for industrial boilers. Operating costs are driven primarily by the consumption of the chemical reagent – usually urea for SNCR - which in turn is dependent upon the efficiency of the control equipment as well as the initial NO_x level and the desired percent reduction. These are typically in the range of \$1,300 to \$10,000/ton of NO_x.

An additional consideration important in the overall operating costs for coal-fired boilers is the potential contamination of fly ash by ammonia, making it potentially unsalable.

SCR

Capital costs for retrofit SCR systems to industrial boilers are mostly within the range of \$4,000 to \$15,000 per MMBtu/hr. Installation of an SCR on a boiler is site-specific and this results in a range of capital costs for SCR systems on boilers. Coal-fired boilers have higher capital costs. The systems must be larger to allow for flow of fly ash through the catalyst without plugging. Catalyst activity deteriorates faster in coal-fired boilers because of the higher levels of contaminants in the flue gas (like arsenic) and the deposition of ash on the catalyst. Catalysts must be replaced more frequently in coal-fired systems, which increases the operating cost. The lower end of this range applies to retrofits with nominal difficulty. The high end of the range would typically be associated with retrofits having significantly impeded construction access, extensive relocations, and difficult ductwork transitions.

In addition to catalyst replacement costs, operating costs are mainly driven by cost of reagent, energy penalty (pressure loss, ammonia vaporization) and dedicated O and M costs. SCR technology offers very high NO_x reductions (80 percent or better); the cost per ton of NO_x removed is considerably higher than SNCR, although the overall NO_x reduction is higher.

3.4.2. SO₂ Technologies

Both wet and dry scrubbers are in wide commercial use in the U.S. The capital costs for new or retrofit wet or dry scrubbers are high when compared to the capital costs

for NO_x and PM controls (Khan, 2004b). Dry sorbent injection (DSI) has lower capital costs than a spray dryer absorber (SDA), although DSI can only achieve about 40 percent SO₂ reduction. SDA systems can achieve 90 percent reduction. Capital costs for DSI are in the range of \$8,600 to \$26,000 per MMBtu/hr, depending on the size of the system and on the sulfur content of the fuel. Capital costs for SDA systems are about double that for DSI systems, but the cost per ton of SO₂ removed is similar: \$400 to \$4,000 per ton of SO₂ removed. These costs are higher than the costs for scrubbers on EGUs, which are only \$100 to \$200 per ton of SO₂ removed.

Wet FGD systems also remove 90 percent and higher of the SO₂, but the capital cost is about 50% higher than the cost for an SDA system. The costs per ton of SO₂ removed are similar to the costs for SDA for coal-fired boilers. Costs per ton of SO₂ are estimated to be about twice as high for oil-fired boilers as compared to coal-fired boilers.

3.4.3. PM Technologies

As with most control technologies, the costs of PM controls involve both capital and operating costs. A cost-effectiveness indicator, such as \$/ton as is typically used for other technologies (e.g. NO_x and SO₂), is very difficult to address for generic PM control costs, as the range of PM reductions for different fuels and processes is so wide that cost ranges become useless. An attempt to summarize costs in terms of capital and O&M components is presented below.

Capital

While it is customary to indicate capital costs on a \$/kW basis for power generation applications, this is not relevant for non-power applications since no electricity is generated. However, one of the main parameters dictating the “sizing” and hence, the costs of a PM control device, is the quantity of flue gas it must handle. As a result, it is more appropriate to generalize capital costs per actual cubic feet per minute (ACFM) of gas flow and is given on a “\$/ACFM” basis. The following values represent typical costs for several of these technologies (these numbers reflect unit sizes ranging from utility-size units up to about 2,000,000 ACFM to smaller process down to about 10,000 ACFM))

- Dry ESPs - \$15 - \$40/ACFM
- Wet ESPs - \$15 - \$40/ACFM
- Reverse Air Fabric Filter - \$17 - \$40/ACFM
- Pulse Jet Fabric Filter - \$12 - \$40/ACFM
- Venturi Scrubber - \$5 - \$20/ACFM
- Cyclone - \$1 - \$5/ACFM

O&M

O&M costs are difficult to generalize for such a variety of technologies and applications, as they are affected by many parameters that include type of fuel, type of

process, local ash disposal options, local cost of power, etc. O&M costs include fixed costs (FOM) and variable costs (VOM). The costs provided below are presented in \$/year-ACFM and reflect costs for coal-based fuels but should reasonably apply to other sources as well.

Fixed O&M

- Dry ESPs - \$0.25 - \$0.65/yr-ACFM
- Wet ESPs - \$0.15- \$0.50/yr-ACFM
- Reverse Air Fabric Filter - \$0.35 - \$0.75/yr-ACFM
- Pulse Jet Fabric Filter - \$0.50 - \$0.90/yr-ACFM
- Venturi Scrubber - \$0.25 - \$0.65/yr-ACFM
- Cyclone – Not applicable

Variable O&M

- Dry ESPs - \$0.45 - \$0.60/yr-ACFM
- Wet ESPs - \$0.25 - \$0.50/yr-ACFM
- Reverse Air Fabric Filter - \$0.70 - \$0.80/yr-ACFM
- Pulse Jet Fabric Filter - \$.90 - \$1.1/yr-ACFM
- Venturi Scrubber - \$1.2 - \$1.8/yr-ACFM
- Cyclone – Not applicable

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Table III-4. NO_x reduction and control costs for industrial boilers (Khan, 2004a).

Fuel	Technology	NO _x Reduction	\$ /Ton of Pollutant vs. Boiler Size			Capital Costs \$/ MMBtu/hr vs. Boiler Size		
		%	1000 MMBtu/hr	250 MMBtu/hr	100 MMBtu/hr	1000 MMBtu/hr	250 MMBtu/hr	100 MMBtu/hr
Gas	LNB/OFA	60	280 - 5260	424 - 7973	559 - 10521	1280	1940	2554
Gas	LNB/OFA/GR	80	368 - 6204	543 - 9415	700 - 12374	2000	3031	3991
Oil	LNB/OFA(1)	30	306 - 2630	464 - 3986	612 - 5260	1280	1940	2554
Oil	LNB/OFA/GR (1)	50	326 - 2505	477 - 3790	615 - 4973	2000	3031	3991
Oil	LNB/OFA/GR (2)	30	741 - 5694	1085 - 8613	1399 - 11303	2000	3031	3991
Coal	LNB (subbit.)	51	256 - 1520	389 - 2305	512 - 3033	2554	3872	5097
Coal	LNB/OFA (subbit.)	65	306 - 1727	454 - 2608	593 - 3428	3649	5531	7281
Coal	LNB/OFA (bit)	51	392 - 2197	581 - 3317	757 - 4358	3649	5531	7281
Gas	SNCR	40	1842 - 14165	2193 - 20870	2521 - 27105	2111	3200	4212
Oil	SNCR (1)	40	1485 - 4271	1670 - 5892	1840 - 7399	2045	3100	4081
Oil	SNCR (2)	40	1628 - 5497	1889 - 7753	2123 - 9842	2045	3100	4081
Coal	SNCR	40	1285 - 2962	1473 - 4015	1625 - 4970	2639	4000	5266
Gas	SCR	80	986 - 14815	1354 - 21095	1689 - 26859	4014	6084	8009
Oil	SCR (1)	80	760 - 10458	997 - 14443	1245 - 18544	5547	8407	11067
Oil	SCR (2)	80	1017 - 14601	1343 - 20113	1694 - 25838	5547	8407	11067
Coal	SCR	80	876 - 4481	1123 - 5924	1349 - 7262	7298	11062	14562

Notes

(1) 0.5 lb/MMBtu inlet NO_x(2) 0.36 lb/MMBtu inlet NO_x

Table III-5. SO₂ reduction and control costs for industrial boilers (Khan, 2004b).

Fuel	Technology	SO ₂ Reduction	\$/Ton of Pollutant vs. Boiler Size			Capital Costs \$/ MMBtu/hr vs. Boiler Size		
		%	1000 MMBtu/hr	250 MMBtu/hr	100 MMBtu/hr	1000 MMBtu/hr	250 MMBtu/hr	100 MMBtu/hr
Coal	DSI high S coal	40	633 - 1703	763 - 2471	943 - 3543	12508	18838	26835
Coal	DSI lower S coal	40	697 - 1986	849 - 2952	1075 - 4283	8648	12987	17995
Coal	SDA	90	381 - 1500	569 - 2611	790 - 3920	20275	36226	54679
Coal	Wet FGD high S coal	90	373 - 1789	528 - 2708	664 - 3513	32313	48857	64240
Coal	Wet FGD lower S coal	90	461 - 2273	661 - 3460	836 - 4495	29888	45283	59598
Oil	Wet FGD	90	693 - 5082	1011 - 7801	1285 - 10160	27455	41604	54761

4. PORTLAND CEMENT KILNS

Portland cement is a main ingredient for concrete and other common building materials. Portland cement is mainly composed of clinker, a material formed by heating limestone and other ingredients to temperatures over 2,650°F. High combustion temperatures require significant amounts of fuel and can result in significant emissions of NO_x and SO₂. Crushing of ingredients and finished clinker can release dust and particles. Ammonia is sometimes produced during the heating of limestone.

The cement industry has seen significant growth in capacity and technology over the last 30 years. In 2000, the U.S. had 201 cement kilns with the annual capacity to produce 84 million metric tons of concrete, with production projected to grow to 109 million metric tons in 2004 (Portland Cement Association, 2000).

4.1. Description of Cement-Making Processes

Concrete is a combination of Portland cement, sand, and gravel. The key component of Portland cement is clinker, a material produced by heating limestone and other raw materials to temperatures over 2,650°F, requiring combustion temperatures of about 3,000°F. These high temperatures are normally achieved in a rotary kiln, as shown in Figure IV-1. Feed material is added at the elevated end of the rotating, refractory-lined, cylindrical kiln and the feed gradually tumbles to the high-temperature end of the kiln and the main combustion zone, sometimes referred to as the "Burn Zone." The tilted design of the cement kiln allows gravity to assist the motion of the clinker material while hot exhaust gases move upward and exit at the elevated end of the kiln.

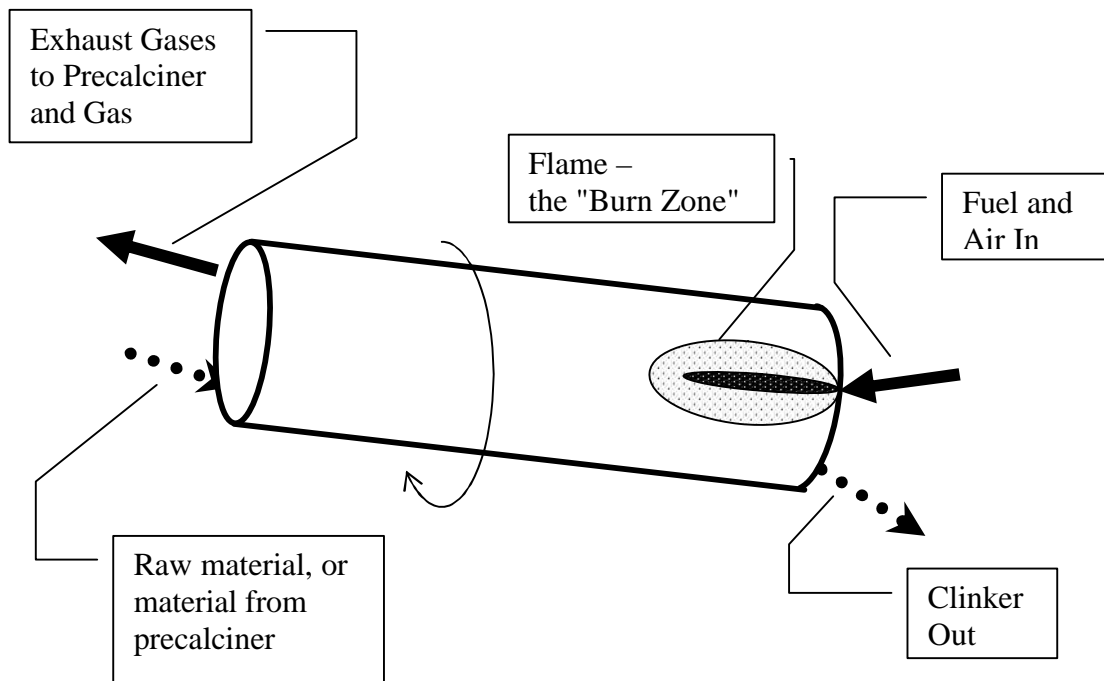


Figure IV-1. Simplified Sketch of a Rotary Kiln.

Cement kilns fall into four general process categories. Preheater kilns preheat and partially calcine feed material in a series of cyclones or grates prior to admitting the feed to the rotary kiln. This additional heat supplements the heat in the exhaust from the kiln. The calcined feed then enters the rotary kiln at about 1,500°F to 1,650°F. Precalciner kilns, on the other hand, utilize a burner in a separate vessel along with a series of cyclones or grates to preheat and calcine the feed. In long kiln systems, the raw feed material is added to the rotary kiln itself as either a powder (“dry”) or a slurry (“wet”). Long wet and long dry kilns do not have preheaters and have much longer rotary kilns, with wet process kilns being the longest - normally several hundred feet long. Preheater and precalciner kilns are more energy efficient than long wet or long dry kilns and typically have greater capacity. A preheater kiln is similar, but fuel is not added and there is no burner on the cyclonic preheater portion. Preheaters could also be replaced with suspension preheaters, but these are less common. If past trends continue, many of the existing long wet kilns and dry kilns are expected to be replaced with precalciner and preheater kilns since precalciner and preheater kilns are more energy efficient and also typically have greater capacity.

Coal is the fuel of choice in cement kilns, primarily because of its low cost, but also because the coal ash contributes somewhat to the product. The current fuel use in cement kilns is about 82% coal; 4% natural gas; and 14% other fuels, mainly combustible waste (industrial waste, tires, sewage sludge, etc.). Fuel nitrogen therefore contributes a small but significant amount to the total NO_x for nearly all cement applications (see the section on NO_x controls included later).

Recent years have seen Portland cement plant capacity stretched by high demand, making technologies that can increase capacity without increased capital expenditures very attractive. The industry is therefore developing technologies that improve facility’s outputs or reduce their operating costs. Incidentally, some of these technologies also offer the potential to reduce NO_x and other emissions.

4.2. Review of BART-Eligible Cement Kilns in the MANE-VU Region

NESCAUM’s analysis of BART-eligible sources in the MANE-VU Region⁶ (NESCAUM, 2004) identified two Portland cement facilities as being eligible for BART. The facilities are shown in Table IV-1. *[Editor’s note: Additional facilities are likely to be added when PA and NY inventories are complete]*

⁶ NESCAUM does not believe that there are any BART-eligible sources in the State of Vermont or any of the member Tribes in MANE-VU and thus we have not developed lists for these jurisdictions. In addition, Pennsylvania and the District of Columbia have developed BART-Eligible source lists following their own methodology and any identified sources are contained here and in the final list in Appendix A.

Table IV-1 BART-Eligible Portland Cement facilities in MANE-VU Region

Facility	Kiln type	Capacity, thousands tons/yr	Primary Fuel(s)
St. Lawrence Cement (Hagerstown, MD)	Dry	550	Coal
Dragon Products (Thomaston, ME)	Wet	392	Coal, petcoke

4.3. Available Control Technologies

A number of technologies exist for controlling emissions from cement kilns. Secondary (post-combustion) control devices can be helpful in reducing emissions, and a variety of these are available. Many technologies and techniques have been developed in response to a specific environmental need and target a specific pollutant, sometimes achieving reduction in other pollutants at the same time. Both secondary controls and process changes are discussed below, grouped by their targeted pollutant. When additional emissions reductions are possible, they are noted with the targeted pollutant. Controls are examined for SO₂, NO_x, PM, and VOCs.

4.3.1. SO₂ Controls

In contrast with electric utility boilers, SO₂ emissions from rotary kilns producing cement clinker under oxidizing conditions are nearly independent of fuel sulfur input, but, rather, are closely related to the amount of sulfide (e.g. pyrite) in kiln feed and to the molar ratio of total sulfur to total alkali input to the system. In cement kilns SO₂ emissions generally depend on:

- Inherent SO₂ removal efficiency of kiln system,
- Form of sulfur (e.g. pyritic) and sulfur concentrations in raw material,
- Molecular ratio between sulfur and alkalis,
- Prevailing conditions (oxidizing or reducing) and their location within kiln, and
- Temperature profile in the kiln system.

Depending upon the level of sulfur in a plant's limestone compared to the sulfur content of its heating fuel, fuel switching may not be sufficient to reduce SO₂ emissions (Tanna and Schipholt, 2004). However, when fuel sulfur levels are high, fuel switching may have a significant benefit of reducing SO₂ levels.

In addition to the control techniques used in the electric utility boilers, cement plants may also resort to other basic reductions techniques involving reduction of sulfur input to the kiln, by switching fuels or changing the limestone, or reduction of SO₂ emissions from reducing both the sulfur in the sources and using a secondary control device. It is common to achieve some level of SO₂ reductions when seeking to reduce another pollutant, usually NO_x (technologies targeting another pollutant, but also

reducing SO₂, are described in the NO_x and PM sections below). In addition to considering a change in the primary fuel for the kiln, staged combustion with mid-kiln injection of a low-sulfur fuel may be considered for reducing SO₂. Including high-pressure air injection at a mid-kiln firing site can limit oxygen in the kiln and suppress SO₂ formation (Hansen, 2002). Since these techniques are primarily used to reduce NO_x, more information about mid-kiln fuel injection can be found in the section on NO_x emissions, but other specific SO₂ control technologies applicable to cement kilns are listed below.

Fuel Switching

Selecting a fuel with lower sulfur content, a strategy commonly adopted in the utility boilers, is less effective in cement-making systems, where SO₂ emissions are not strongly dependent on fuel sulfur content. Depending upon the level of sulfur in a plant's limestone compared to the sulfur content of its heating fuel, fuel switching may not be sufficient to reduce SO₂ emissions (Tanna and Schipholt, 2004). However, when fuel sulfur levels are high, fuel switching may have a significant benefit in SO₂ levels.

Inherent Removal

Raw materials, primarily limestone, are preheated in the cement-making process either in the preheater tower or in the rotary kiln. In either case, the limestone comes in contact with hot combustion exhaust gases. The calcium in the lime reacts with SO₂ in the gas, providing in-process removal of sulfur in the kiln system. Removal efficiencies in rotary kiln systems range between 38% and 99% of sulfur input, and 50% to 70% of the remaining SO₂ is removed from exhaust gases when passing through an in-line raw mill system (Miller et al., 2001).

Process Alterations

The following methods to remove and prevent formation of SO₂ by modifying or controlling conditions in the system are available due to the nature of the Portland cement manufacturing process:

- The oxygen concentration of the exhaust gases can be controlled to ensure sufficient oxygen exists to stabilize alkali and calcium sulfate compounds formed in the process. Concentrations of O₂ and, more importantly CO, have a strong influence on the stability of alkali and calcium sulfates in the burning zone. Control of burning-zone O₂ and CO concentrations is a widely used industrial practice, and a control technique applicable to all rotary kilns producing cement clinker. The downside of this technique is the more favorable conditions created for generation of NO_x in the rotary kiln.
- Burning-zone flame shape can be modified to minimize localized reducing conditions. It has been observed (Hansen, 1986) that flame impingement in the hot zone had a major effect on SO₂ emissions from the kiln, even if total oxygen is sufficient to fully combust all fuel. Avoiding flame impingement in the burning zone minimizes SO₂ formation. Avoiding flame impingement on the clinker, a technique applicable to all rotary

kilns producing cement clinker, requires proper solid fuel preparation and proper flame shaping and control.

- Raw materials can be altered to affect the alkali/sulfur molar ratio. SO₂ concentrations in kiln exit gases vary with the molar ratio of alkali to sulfur; when alkalis are in excess of sulfur, SO₂ emissions are typically low, due to more sulfur being retained in clinker as alkali sulfates. Also, kiln feed containing carbon seems to directly cause SO₂ emissions. Changing raw materials may reduce SO₂ emissions. Substituting a raw material containing pyritic sulfur or organic sulfur with one containing lesser amounts of these compounds reduces SO₂ emissions. Replacement of raw materials, however, is often constrained by economic considerations, while alkali input increase may also be limited by cement product quality specifications on total alkali in cement.
- Alterations to system can influence SO₂ emissions. It has been found that an improved distribution of kiln feed may equalize temperatures in bottom stage cyclones and reduce SO₂ emission by as much as 20% (Miller, 2001).

Scrubbers

Dry Reagent Injection

Steuch and Johansen (1991) found that Ca (OH)₂ (hydrated lime) was the most effective scrubbing agent, particularly when added to the kiln feed and when the exhaust gases were near the dew point. Adding quicklime or hydrated lime into the upper preheater cyclones demonstrated up to 70% removal efficiency (Nielse, 1991).

Several dry reagent systems are available:

- The RMC Pacific process (Sheth, 1991) injects dry Ca(OH)₂, and with different stoichiometric ratios (40:1 to 50:1), has obtained efficiencies ranging from 55% to 65%. SO₂ removal of 80% was obtained with injection into the roller mill.
- Krupp Polysius Polydesox process uses hydrated lime where SO₂ in the raw feed tends to form from pyrites and obtains removal efficiencies of up to 85% (Miller, 2001).
- De-SoX Cyclone, by Fuller Company (Miller, 2001), reduces SO₂ emissions in a precalciner kiln by removing a portion of the gases from the precalciner outlet to a cyclone, and from there to the Stage II cyclone where pyritic sulfur in kiln feed is decomposed into SO₂. The feed (or “raw meal”), containing freshly produced lime, is discharged into the outlet duct of the second stage (this process is known as hot meal injection). Removal efficiencies of 5 to 30% are claimed.

Lime/Limestone Spray Dryer Absorber

Design stoichiometric ratios of calcium to sulfur for spray dryer systems in utility boilers are typically between 0.9 and 1.5, with most below 1.0. These SO₂ scrubbers are designed for removal efficiencies in excess of 80%.

SO₂ reacts with CaCO₃, to form CaSO₄, a reaction that becomes more complete as the temperature and the fineness of CaCO₃ increase. The presence of water vapor also increases conversion.

Most of the spray dryer type SO₂ control technologies in the cement industry are applied to preheater or preheater/precalciner kilns. Exhaust gases from long dry kilns are cooled by either spray water introduced into the feed end of the kiln or by dilution air-cooling after the gases leave the kiln. Adding a conditioning tower to replace water sprays or dilution air enables the alkaline slurry system to be used to reduce SO₂ emissions (the equivalent of a spray dryer). The range of temperatures for exit gases from long wet kilns does not allow the use of an alkaline slurry spray dryer type scrubber because the addition of the lime slurry may drop the exhaust gases temperature below the acid dew point, creating significant plugging and corrosion problems in the downstream Particulate Control Device (PCD), duct work, and induced draft (ID) fan.

RMC Pacific's Alkaline Slurry Injection System (Sheth, 1991)

RMC Pacific uses a hydrated lime, spray dryer absorber to reduce SO₂ emissions. The captured sulfur compounds are returned as a portion of the raw material feedstock to the roller mill, which results in no scrubber effluent or sludge disposal. When SO₂ emissions are high and preheater exit gas temperatures are low, sufficient lime slurry cannot be added to reduce SO₂ to acceptable levels. With different stoichiometric ratios (40:1 to 50:1), the process has obtained efficiencies ranging from 55% to 65%. SO₂ removal of 80% was obtained with injection into the roller mill.

EnviroCare Microfine Lime System (Miller, 2001)

This system uses the existing gas conditioning tower to introduce the scrubbing reagent (water suspension of finely pulverized calcium hydroxide, Ca (OH)₂). The small size of the lime particles (3-10 microns) allows the particles to dissolve in water droplets quickly and react with SO₂ as it is absorbed into the water droplet. The dried lime continues to react with any remaining SO₂ in the downstream kiln system and PCD. Lime injection rate can be optimized through a feedback control loop from an SO₂ monitor. EnviroCare claims an SO₂ removal efficiency of greater than 90%.

Wet SO₂ Scrubbers

Wet scrubbers have been used successfully in the utility industry. Calcium sulfate scaling and cementitious buildup when a wet scrubber is used for acid gas control applied to the exhaust gas from a cement kiln can be avoided if these systems are installed downstream of a high efficiency PCD (e.g., fabric filter). Failure of the PCD can pose difficult problems for a downstream wet scrubber.

Fuller Company (FLS Miljø) (Miller, 2001)

The Monsanto Dyna Wave wet SO₂ scrubber has been installed by the Fuller Company and used on several cement kilns in the U.S. This wet scrubber is designed to remove SO₂, halide gases, and some particulate matter.

The scrubber, typically located downstream from the kiln PCD and operated under positive pressure, uses limestone as the absorbent. A slurry (approximately 20% limestone and 80% water) produced in the mixing tank is sprayed countercurrent to the gas flow to cool the gases and react with SO₂ forming calcium sulfite (CaSO₃) and calcium sulfate (CaSO₄), which precipitates. Air is sparged into the sump at the bottom of the tower to oxidize CaSO₃ to CaSO₄+2H₂O (gypsum).

Monsanto EnviroChem DynaWave (Miller, 2001)

DynaWave is a "Reverse Jet" scrubber that can simultaneously accomplish several gas cleaning/process needs: hot gas quenching, particulate removal, and acid gas absorption. The reverse jet is an annular orifice scrubber having one to three large-bore nozzles through which a relatively large volume of scrubbing liquid is injected counter to the gas flow to create a froth zone. The gas collides with the liquid, forcing the liquid radially outward toward the wall. A standing wave, created at the point the liquid is reversed by the gas, is an extremely turbulent region where the gas absorption and particulate collection occurs.

The system is a tailpipe system generally installed downstream of the PCD, and operates with a saturated gas stream. Therefore, it would likely be applicable to most if not all the cement kilns. A single-stage DynaWave scrubber in full-scale operation has a reported SO₂ removal efficiency of about 90%. Monsanto EnviroChem claims that multiple units may be installed in series to achieve whatever removal efficiency is required (e.g., 99.9%).

4.3.2. NO_x Controls

The following sections discuss the formation of NO_x in cement kilns, potential NO_x control techniques, NO_x control in the cement industry, and the cost effectiveness of applicable controls.

NO_x Formation in Kiln Systems

Nitrogen oxides (NO_x) are formed during the combustion of fuels in the cement-making process. In kiln exhaust gases, more than 90% of NO_x is NO, with NO₂ generally making up the remainder from rotary kilns producing cement clinkers (Gardeik, 1984). There are three different NO_x formation mechanisms - thermal, fuel, and feed NO_x - typically contributing to NO_x emissions.

Thermal NO_x

Thermal NO_x is formed by oxidation of atmospheric molecular nitrogen at high temperatures (>1,200 °C). Most NO_x formed in the high-temperature environment of the main combustion zone (burning zone) of a kiln is "thermal NO_x". Since the flame temperature in a kiln is significantly above that threshold, a considerable amount of thermal NO is generated in the burning zone.

While conditions in the burning zone of a cement kiln favor formation of thermal NO_x, those prevalent in secondary combustion zones (e.g. calciners, preheater riser ducts and mid-kiln firing in long wet or dry kilns) with temperatures below 1200°C, are less conducive to significant thermal NO_x formation. In that zone, formation of fuel NO_x and feed NO_x is more prevalent.

The amount of thermal NO_x produced is related to fuel type, burning zone temperature, and oxygen content. Therefore, raw materials that are hard to burn (i.e., materials that require more heat input per ton of clinker produced) generate more NO_x.

Fuel NO_x

Fuel NO_x is the result of oxidation of nitrogen compounds in fuel. Fuel nitrogen is only partially converted into NO_x during combustion. The amount formed depends on fuel type, precalciner type and precalciner temperature. NO_x formed in the secondary combustion zone, primarily fuel NO_x (Gardeik, 1984), depends on:

- Nitrogen concentration in the fuel,
- Oxygen concentration in the combustion zone,
- Initial NO concentration in the combustion gas,
- Volatile concentration in the (solid) fuel, and
- Temperature in the secondary combustion zone.

As opposed to the burning zone of the kiln, where higher temperatures result in much higher NO_x formation, higher temperatures (up to 1100°C) in the precalciner may actually reduce NO_x emissions when a fuel containing nitrogen is used (Nielsen, 1990).

In the design of modern low-NO_x calciners, high temperatures and reducing conditions are proven methods for suppressing the formation of fuel NO_x generated in the precalciner, and for destroying thermal NO_x generated in the burning zone of the rotary kiln (Keefe and Shenk, 2002).

Feed NO_x

NO_x emissions can also result from the oxidation of nitrogen compounds in the raw material feed to the kiln (feed NO_x). The range of nitrogen concentrations in various

kiln feeds is 20-1000 ppm (Gartner, 1983) and the potential contribution of feed NO_x to total NO_x emissions is 0.2-10 lbs of NO_x per ton of clinker.

Up to 50% of feed nitrogen may be converted to NO_x, if raw materials are heated slowly: with rapid heating, the conversion rate is much lower.

The following conclusions can be made for rotary kiln systems (Young and von Seebach, 1999):

- Formation of thermal NO_x in the burning zone is the major contributor to NO_x emissions from the kiln
- Fuel NO_x is the major contributor in the secondary combustion zone of precalciner and riser duct fired preheater kilns
- Feed NO_x is usually a minor contributor to the total NO_x generated in rotary kiln systems.

It should be further noted that, due to the dynamic nature of kiln operations, NO_x formation can be highly variable so each kiln will tend to have unique NO_x emission characteristics, inherent to the variability in cement manufacturing process. Figure IV-2 illustrates the wide range of NO_x emissions from different types of kilns.

NO_x emissions rates are also site- and kiln-specific, and may be quite dissimilar between two apparently identical kilns, for causes not fully understood, but, probably connected to the raw materials used. Other causes for NO_x emissions rate differences may result from different types or classes of cement products being produced; chemical variations between these different products can influence cement kiln operating parameters and thus NO_x emissions. Short-term process transients such as kiln feed rates and fuel quality also affect NO_x emissions. All of these factors can influence the applicability and costs of incorporating NO_x controls.

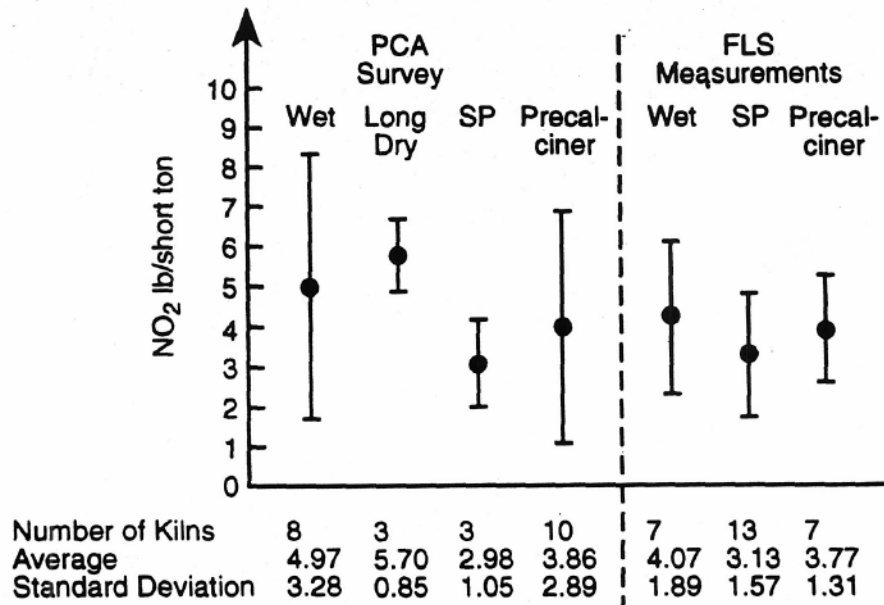


Figure IV-2. NO_x emissions for various cement kiln types (USEPA, 1994). (SP: Suspension Preheater kilns)

NO_x Control Techniques

There are two broad categories of NO_x reduction techniques for cement kilns: 1) process controls, including combustion modifications, that rely on reducing or inhibiting the formation of NO_x in the manufacturing process (modifications for cement kilns include low-NO_x Burners (LNB), secondary combustion, and staged combustion); and 2) post-combustion (secondary) controls, where flue gases are treated to remove NO_x that has already been formed.

It should be noted that the quality of clinker produced in a kiln varies with characteristics of the combustion, so primary controls need to be selected carefully. Dry low-NO_x (DLN) operation, for example, has seen varied levels of success. The main firing zone of the kiln requires very high temperatures and is not compatible with the lower flame temperature used by DLN to reduce NO_x. Low excess air and air-staging are problematic control options for kilns because the kilns need an oxidizing environment not provided by those techniques. Despite these problems, indirect firing in combination with a LNB has been successfully used in some facilities, including California Portland Cement. Low-NO_x combustion methods can be used in the precalciner because high temperatures are not required in that part of the process.

Indirect firing is a method that permits use of LNBs in the primary kiln burning zone. When indirect firing is used, pulverized coal is fed to and collected in a particulate matter collection system (a cyclone separator that exhausts gas through a fabric filter).

The pulverized coal is then temporarily stored in a bin or hopper, where it is fed to the burner. This method allows less primary air to be used in the burner than with a direct-fired coal mill, resulting in less thermal NO_x.

LNBS can be used when indirect firing is employed. When implementing indirect firing with LNBS, other process improvements are often implemented, such as better process controls. According to Portland Cement Association (1998), 20%-30% NO_x reductions can be achieved from the use of indirect firing with LNBS and associated process modifications.

Combustion modifications are less successful at reducing NO_x emissions in thermal processing applications (like cement kilns) than in boilers for steam and/or power production. Chemical reactions producing cement clinker require high material and gas temperatures, and product quality also requires an oxidizing atmosphere in the combustion zone of a cement kiln. Excessively high temperatures in the burning zone pose equipment damage risk, while temperatures too low will no longer produce a salable product.

NO_x emissions can also be affected by kiln feed chemical characteristics, feed chemical uniformity, and specific fuel consumption. As stated by EPA's NO_x Alternative Control Technique Document for the Cement Manufacturing Industry (USEPA, 1994), "For any given type of kiln, the amount of NO_x formed is directly related to the amount of energy consumed in the cement-making process. Thus, measures that improve the energy efficiency of this process should reduce NO_x emissions in terms of lb of NO_x / ton of product."

Following are some of the more common process modifications that have been made to reduce NO_x emissions from cement kilns (NESCAUM, 2001):

- Changing fuel (e.g. natural gas to coal firing).
- Improving kiln feed chemical uniformity, for more stable kiln operations:
 - Modifications to quarry operations,
 - Raw material blending facilities, and
 - On-line analytical control systems for raw material proportioning (e.g. kiln feed blending systems).
- Modifications to improve thermal efficiency, including:
 - Reducing excess air infiltration,
 - Increasing efficiency of cyclones in preheater kilns,
 - Reducing the amount of moisture in slurry (wet process kilns only),
 - Revising kiln chain systems in long wet or long dry kilns,
 - Modifying or replacing clinker coolers to improve heat recovery and cooler efficiency,
 - Initiating operator training programs, and

- Returning as much cement kiln dust (CKD) as possible to the kiln system (without adversely affecting product quality).
- Installing or upgrading kiln system sensors and instrumentation.
- Installing or upgrading computer controls of kiln systems to stabilize kiln operation and avoid burning zone temperature variations.

According to Young and von Seebach (1999), industry data and experience show that control of burning zone temperature is the primary process control method applicable to lowering thermal NO_x formation. Process modifications that allow better control of the kiln burning zone temperature will result in reducing thermal NO_x formation and minimizing NO_x spikes. Stable kiln operation, through feed chemical uniformity, results in overall NO_x reductions of 10% - 15%, while poor kiln feed chemical uniformity results in overfiring the kiln, and higher NO_x emissions.

Fuel Switching

Switching to a lower-nitrogen fuel in a precalciner may reduce NO_x emissions, but the nitrogen content of the fuel burned in the burning zone has little or no effect on NO_x generation. Generally, no relationship has been found between fuel nitrogen content and the NO_x emissions from a cement kiln (Miller and Egelov, 1980).

Process Optimization and Automated Control

Process optimization is a common method for reducing NO_x emissions from cement kilns. In principle, any effort that reduces the amount of fuel being fired to produce clinker will result in a reduction in NO_x generation. In practice, process optimization often entails the use of advanced computer controls and instrumentation. Many of the primary NO_x control technologies described are implemented along with process optimization to take advantage of their combined effects and to improve overall facility operation. NO_x reductions reported in this Chapter are generally attributed to the changed combustion process (for example, mid-kiln firing). Combined reductions reported in a case study (NESCAUM, 2001) equivalent to 55% reduction in average NO_x emissions - from 845 lb/hr to 383 lb/hr – were achieved largely by reducing the variability of the process with a computer-automated optimization system. Mid-kiln firing provided additional NO_x reduction for an overall NO_x emission reduction of 59% from controls.

Flue Gas Recirculation

Flue gas recirculation (FGR) or water/steam injection into the main flame to reduce flame temperatures and NO_x formation is not a viable method of reducing NO_x in a cement kiln burning zone. FGR's effectiveness relies on cooling the flame and generating an oxygen deficient (reducing) atmosphere for combustion to reduce NO_x formation, conditions that are not compatible with cement kiln operation. High flame

temperature and an oxidizing atmosphere are process requirements to produce a quality clinker product.

Indirect Firing

Conversion from a direct coal firing system to an indirect firing system kiln with a low NO_x burner may result in NO_x reductions ranging from 0% to about 20% (Kupper et al., 1990; Schrsemli, 1990). Incorrect use of multi-channel (low NO_x) burners can increase NO_x rather than reduce NO_x, and it has been found (Hansen, 1985) that less excess air in the kiln combustion gases results in less NO formation at the same burning zone temperature. NO_x reductions of 15% were reported.

Low-NO_x Burners

LNBs have been successfully used in the primary burn zone and especially in the precalciner kilns.

Secondary combustion zones have proven effective at reducing NO_x emissions in cement kilns. In long kilns, secondary combustion can be partly accomplished by mid-kiln injection of fuel (less than 20% of kiln fuel). NO_x emissions are reduced because less fuel is burned in the high temperature environment of the burning zone. Another NO_x reducing technique is the use of fuel in the riser duct of preheater kilns, although, because of high prevailing temperatures, such reductions do not always occur. With precalciner kilns, which employ a secondary combustion zone at a much lower temperature than the burning zone, typically 60% of the fuel is burned in the precalciner, with the combustion air coming directly from the clinker cooler, and NO_x emissions for these kilns are less than from long wet, long dry, or preheater kiln systems because 60% of the total fuel requirement is burned under lower temperature conditions where negligible amounts of thermal NO_x are formed. Furthermore, precalciner kilns have the potential for staged combustion as a NO_x control technique. All major equipment suppliers offer "low-NO_x" precalciner designs. Fuel burned in a sub-stoichiometric O₂ environment creates a strongly reducing atmosphere (relatively high concentrations of CO) that inhibits formation of fuel NO_x and destroys a portion of the NO_x formed in the kiln burning zone. Additional tertiary combustion air is added later to complete combustion of the fuel.

Staged combustion has become a well-known method for reducing NO_x emissions from cement plants, but as NO_x and CO emissions limits become more stringent, control via fuel and air staging are coming under reconsideration. Low- NO_x calciners combine high temperature combustion and firing under reducing conditions without staging fuel/air.

Low-NO_x Precalciners

Precalciner kilns can employ LNBs because the temperature in the precalciner can be low enough to reduce thermal NO_x but still be effective in heating the limestone.

Since roughly 60% of the fuel burned in a precalciner kiln is fired in the precalciner, NO_x reductions can be substantial. All new precalciner kilns are equipped with low-NO_x burners in the precalciner. Low-NO_x precalciners have been shown to reduce NO_x by 30%-40% compared to conventional precalciners (Young and von Seebach, 1998). This reduction is from the precalciner-generated NO_x, not for the entire kiln.

Several precalciner kilns in the U.S. have recently been retrofitted with these "two-NO_x" calciners, and several new kiln lines have been installed using low-NO_x precalciner technology. Operating experience indicates a noticeable reduction in NO_x per ton of clinker. Industry reports place the NO_x reduction potential of staged combustion with a low-NO_x precalciner at 30% - 40% when compared to a conventional precalciner kiln system.

Low-NO_x precalciner is a proven way to reduce NO_x emissions in a cement-making system, and all new cement-making systems are expected to be built with it. They come in two types, "in-line", commonly used with "normal" fuels (e.g. coal, oil, gas), or "separate-line", selected for difficult-to-burn fuels (e.g. petroleum coke and anthracite) because its high oxygen atmosphere ensures improved fuel burnout. In-line calciners have lower specific NO_x emissions than separate-line ones, but both are capable of meeting current CO/NO_x emission standards for any combination of fuel and feed, and both are dependent on the presence of strong reduction and oxidation zones.

CemStar

Another approach that has been proven effective in reducing NO_x is the patented CemStar process, originally developed and sold as a method to increase production of clinker from existing kilns while minimizing capital expenditures (Young, 1995; Young, 1996). In the CemStar process, steel or blast furnace slag is introduced as feed material into the kiln. The slag is generally added at the inlet to the rotary kiln (typically after the precalciner or preheater), regardless of kiln type. Unlike normal cement materials, which require significant processing to achieve adequate grain size, the slag need only be crushed to 3/4 to 1-1/2 inch pieces. Minimal processing is necessary because the slag has a low melting temperature and its chemical nature is very similar to the desired clinker. Minimal slag processing permits the equipment for the CemStar to be inexpensive and also reduces energy consumption per unit of clinker produced. Moreover, the CemStar process can be implemented on a kiln quickly with minimal impact to facility operations. The equipment needed is mostly material handling equipment.

The CemStar approach has many advantages: energy input can be reduced, NO_x emissions (both lbs/hr and lbs/ton of clinker) can be reduced, and kiln capacity can be increased. Since the steel slag more closely resembles the desired kiln product than do the normal raw materials, kilns with CemStar require less intense firing and allow for a significant reduction of peak burn-zone temperature. The lower burn zone temperature results in less thermal NO_x generation. NO_x reduction may be expected to be in the range of 20% or more for most kilns. If initial, uncontrolled NO_x is high due to thermal NO_x, CemStar is likely to provide reductions on the order of 40%-50%. Results of controlled testing of CemStar with baseline conditions resulted in 20% reduction in NO_x,

corresponding with a reduction in average burn-zone temperature of over 200°F. Kiln capacity is increased because each ton of steel slag added to the kiln results in about a ton of additional production, though the precise amount of additional kiln production is dependent on the mineral characteristics of the local raw material. This capacity increase is the reason that many facility owners may initially choose to use CemStar.

TXI, the developer of CemStar, reports that more than 10 plants are currently equipped with the technology. NESCAUM (2001) discusses one application of CemStar on a long-wet process kiln.

Mid-Kiln Firing

Mid-kiln firing entails injecting a fuel, usually tires, mid-way through long dry and long wet kilns. This method has been shown to reduce NO_x by about 30% with mid-kiln heat input comprising about 20% of the total heat input (Portland Cement Association, 1998). Results of tests of mid-kiln firing on several kilns are summarized in Table 2 (NESCAUM,2001). The average NO_x reduction for these kilns is about 27%. Mid-kiln firing reduces the heat needed, and therefore the thermal NO_x produced in the primary burn zone. Fuel NO_x will also be reduced because tires and other mid-kiln fuels have low nitrogen contents. Nitrogen content in tires is roughly one fifth that of coal on a mass basis, while heating value on a mass basis is similar (Schrama et al., 1995; Stillwater and Wahlquist, 1998). Coal can be used as a mid-kiln firing fuel, but tires are preferable because they provide a revenue source when kiln operators are paid a tipping fee for taking whole tires. Other revenue-generating fuels could potentially be used as well.

Table IV-2 NO_x Reduction at Cement Kilns Using Mid-Kiln Technology (NESCAUM,2001)

Initial NO _x (ppm)	936	1372	1342	1359	565	513
Final NO _x (ppm)	790	994	600	883	488	456
% Reduction	16%	28%	55%	35%	14%	11%

High-pressure air injection, mentioned in the previous section as a potential control for SO₂ emissions, was primarily developed as a NO_x reduction strategy (Hansen, 2002). The technique was designed for use with staged fuel combustion (mid-kiln firing) and mixing air. Mid-kiln firing with mixing air creates stratified thermal layers in the kiln, preventing immediate combustion of the mid-kiln fuel and lowering exit oxygen levels enough that additional CO is produced. Injecting high-pressure air into the kiln provides energy to mix the layers, lowering the main flame temperature and creating a reducing area between the fuel and air injection points, which encourages the destruction of NO_x. The technique has been shown to reduce NO_x by about 50%, while also reducing CO by 47% and SO₂ by 97%.

Biosolids Injection

Biosolids Injection (BSI) is a technology that was developed in the 1990's by the cement industry for NO_x reduction in precalciner and preheater kilns (Biggs, 1995). BSI adds dewatered sewage sludge to the mixing chamber of the precalciner. The dewatered biosolids provide a source of ammonia, producing an SNCR reaction to reduce NO_x. At a Mitsubishi Cement Kiln in California, BSI provided about 50% reduction in NO_x from about 250 ppm (at 12% oxygen) to 120-125 ppm (at 12% oxygen). BSI has the additional benefit of offering a potential revenue stream because many communities are willing to pay a tipping fee for accepting biosolids. BSI technology may require significant capital equipment expenditures, however. The material handling equipment needed and the moisture in the dewatered biosolids is sufficient to strain the capacity of the fans of many existing facilities. It appears that biosolids injection may be an effective approach for NO_x reduction, but it will depend on the specifics of the kiln.

Selective Non-catalytic Reduction

Selective Non-catalytic Reduction (SNCR) of NO_x is based on the injection of a reagent, typically NH₃ or urea, into the kiln system at a location with an appropriate temperature window 1140 – 2010oF (870 - 1100°C). Some researchers have found that the most effective temperature range is narrower, about 1650 – 2000°F (900 - 1000°C). Temperature is critical because no catalyst is used. At temperatures too high, the reagents will form additional NO_x, and, at low temperatures, the reactions proceed slowly and promote the escape of substantial amounts of unreacted ammonia. Under optimum conditions about one mole of NH₃ is required to reduce one mole of NO_x, but the amount of NH₃ is always critically dependent on the reaction temperature. Ammonia slip, which increases rapidly when the molar ratio of NH₃ to NO is above one, causes a detached plume and can increase opacity of the stack gases.

Preheater and precalciner kilns operate with kiln gas exit temperatures in the appropriate temperature range. SNCR systems have been used on some preheater kilns in Europe. For wet and long dry kilns, these temperatures exist midway through the kiln. Access to this area is possible only through ports in the kiln shell as used in mid-kiln firing or with scoops used to return cement kiln dust. Ammonia must be added continuously in a fixed molar ratio to NO_x in order to be effective and to minimize ammonia slip. Therefore, SNCR is not technically feasible at this time on long wet process or long dry process kilns.

SNCR has been tested in the U.S. on precalciner kilns and is planned for commercial use in other countries (Steuch et al., 1994; Sun et al., 1994). Experience is limited to only a few units worldwide, but some tests have reported significant reductions. Table 3 lists commercial installations of urea SNCR on precalciner kilns and the results of some demonstration programs. Effective operation of SNCR requires availability of a section of kiln with the proper temperature and residence time characteristics for good reduction. The specifics of the installation will determine the level of reduction that is possible. It is unlikely that SNCR can be used effectively on many long kilns (wet or dry) because of the need for access to the proper temperature

region for injecting urea or ammonia reagent. However on some precalciner kilns the access to the proper temperature zone is good.

Although SNCR technology has the potential to offer significant reductions on some precalciner kilns and it is being used in numerous cement kilns in Europe, it has been tested in only one facility in the U.S.

Table IV-3 NO_x Reduction Performance of Urea SNCR on Precalciner Cement Kilns (NESCAUM, 2001)

Company / Location	Unit Type	Size (MMBtu/hr)	NO _x Baseline	Reduction (%)	NH ₃ SLIP, (ppm)
Ash Grove Cement Seattle, WA (Demo)	Cement Kiln/ Precalciner	160 tons solids/hr	350-600 lb/hr	>80	< 10
Korean Cement Dong Yang Cement, Korea (Demo)	New Suspension Precalciner	na	1.27 lb/MMBtu	45	na
Taiwan Cement Units #3, #5, & #6	Cement Kiln/ Precalciner	260 697 658	1.29 lb/MMBtu 1.58 lb/MMBtu 0.92 lb/MMBtu	50 45 25	15 15 15
Wulfrath Cement Germany (Demo)	Cement Kiln	140	1000 mg/Nm ³ 500 ppm	90	na

Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) uses ammonia, in the presence of a catalyst (e.g. titanium dioxide; vanadium pentoxide), to selectively reduce NO_x emissions from exhaust gases. SCR has been extensively and quite successfully used in a very cost effective manner on coal- and gas-fired utility boilers, industrial boilers, gas turbines and internal combustion diesel engines in the U.S. Typically, anhydrous ammonia, usually diluted with air or steam is injected into hot flue gases, which then pass through a catalyst bed where NO_x is reduced to N₂ gas and water. The optimum temperature for SCR depends on the catalyst but is usually between 570 and 840°F (300 and 450°C).

Exit gas temperatures from dust collectors on wet kilns, for long dry kilns, and for dust collectors in preheater kilns that use in-line raw mills for grinding and drying raw materials are relatively low and flue gases would have to be reheated before employing SCR. This technology so far has not been applied to the cement kilns but is being

evaluated by some of the state air permitting agencies as Best Available Control Technology (BACT) for some of the new cement kilns being proposed in the U.S.

Combination of Technologies

It is not uncommon to combine combustion technologies with post-combustion technologies for other source types, and this could be done for cement kilns in some cases. It is also possible to combine multiple combustion technologies on cement kilns. For example, one of the case studies in *Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines; Technologies and Cost Effectiveness* (NESCAUM, 2001) combines indirect firing and mid-kiln firing to reduce NO_x by a combined amount approaching 50%. It is also reasonable to expect that technologies such as CemStar might be combined with a combustion technology such as mid-kiln firing to provide combined benefits, and it may be feasible to use SNCR or SCR in combination with other controls for cement kilns. The exact amount of reduction will depend upon the regulatory requirements and technical limitations. In some cases the NO_x reductions may not be additive.

4.3.3. PM_{2.5} Controls

The particulate matter exiting the kiln system with the exhaust gases is relatively coarse, with most of the particulate matter having diameters greater than 10 microns, but the concentrations of particles in the exhaust can be several times higher than in a coal-fired power plant. Particulate control devices for cement plants must be able to clean gases with fairly high dust loading.

As is the case for many other industrial sectors, the main control options for fine particles are baghouses (more formally known as Fabric Filters) and electrostatic precipitators (ESPs), described in Section 2.3.2 (EGUs). The following section describes some issues specifically related to cement kilns and the use of these devices, including a new filter system combining a baghouse and an ESP.

Cement kilns primarily utilize baghouses of the reverse-air and pulse-jet types. Both types are usually configured so that the bags can be cleaned during an “off-line” cycle, in which a section of the baghouse is closed off from the main exhaust flow for cleaning. This tends to reduce the need for a high-pressure pulse that causes additional wear on the filtration fabric, allows less time for particles to be collected in the hopper during its brief and frequent use, and requires additional power for operation. The choice between a reverse-air and pulse-jet system is generally made on the basis of the volume of exhaust and production from the kiln. In general, kilns producing less than 1650 stpd (with exhaust volumes below 128,000 acfm) are most efficiently served by a jet-pulse system (D’Lima and Pirwitz, 2000). The decision is more complex for kilns up to 6600 stpd (with exhaust volumes up to 853,000 acfm), for which initial equipment costs are similar but lifetime operation costs are more complicated. D’Lima and Pirwitz (2000) concluded that jet-pulse systems are appropriate for the smallest kilns and reverse-air

systems are preferred for all larger kilns, even though they may have higher installation costs for kilns of more modest size.

Corrosion in baghouses has been an important topic in the cement kiln control literature (Jansen and Mazeika, 2003; Biege and Shenk, 2001). A 2002 EPA rule [40 CFR Part 63 Subpart LLL (2002)] requires gas temperatures entering the control device not to exceed 400°F (205°C) in order to control dioxin emissions. Water sprays are usually utilized to control exhaust temperature, but adding water vapor to the exhaust stream while lowering exhaust temperature brings the gas near the dew point of some corrosive components. Corrosion issues can be addressed in a number of ways, but all add cost to the use of the control system.

The three components of corrosion are corrosive gases, condensation, and a corrodible surface; reducing any component will reduce corrosion. Corrosive gases can be reduced in a roller mill; this may be one of the most effective methods to reduce corrosion. Many of the gases are absorbed by the feed during the milling process and are therefore not available to form acids in the exhaust. Changing the feed may also reduce some of the acidic gases. Condensation is prevented most easily by keeping the exhaust temperature hot; however, when this is not allowed, it is best to maintain the exhaust temperature as high as possible, preventing drops which may allow acidic condensation. Insulating surfaces and carefully sealing unused sections of the control device can prevent exhaust from leaking into cool areas where it can condense and cause corrosion. Finally, corrosive-resistant materials and acid-resistant coatings can help reduce corrosion in control equipment.

Instead of a baghouse or an ESP, a combined system has become available, utilizing components of both systems. Whereas an in-series, hybrid system has the ESP and baghouse systems in independent compartments, this technology is described as “an ESP in which every other row of discharge electrodes is replaced by a single row of filter bags” (Gebert et al., 2003). In this new system, where the filter bags are directly adjacent or parallel to the ESP electrical field, ESP zones alternate with filter zones, allowing primary collection by the ESP and pre-ionization of the remaining dust for collection on the filter bags. A highly efficient expanded polytetrafluoroethylene (ePTFE) membrane is used as the filter fabric, which can remove an order of magnitude more of fine particulate than ordinary bags. During a pilot system test of a 225 m³/min (9000 acfm) slipstream from a coal-fired power plant in South Dakota, greater than 99.99% removal efficiency was shown. With the ESP fully engaged, bag cleaning was required only every 300 minutes, compared to every fifteen minutes when the ESP was not used. This system has been utilized in full-scale commercial operation at a cement kiln in Italy since September 2002, capturing dust from the cement kiln, raw mill and clicker cooler. Another similar filter is in operation since October 2002 at the coal-fired power plant in South Dakota mentioned above.

The synergy between the two technologies enables operation of the filter bags at high air-to-cloth (A/C) ratios, and, combined with the new compact size for filters, provides the following benefits for a cement plant:

- Ability to reach high control efficiencies in all operation modes,
- Continuous stable operation, and

- Lower operating costs, due to reduced number of system components.

4.3.4. VOC Controls

No controls which specifically targeted VOCs were identified for cement kilns.

4.4. Costs and Availability

4.4.1. Sulfur Dioxide Control

The SO_x control techniques applicable to the cement industry and the assumed SO_x reductions that the various control technologies can achieve are summarized in Table IV-4.

The achievable SO_x reductions vary greatly. Even when the same control technology is applied to kilns of the same type, the removal efficiency will depend on kiln operating parameters, uncontrolled SO_x emissions rate, and many other site-specific factors.

Wet-limestone scrubbers and spray dryers can be used as secondary control devices to reduce SO₂ emissions from a cement kiln.

Capital and operating costs for spray dryers and wet scrubbers as applied to cement kilns were computed by Young (2002). Both technologies were assumed to be installed *after* the existing APCD, which would allow the CKD to be recycled back to the kiln. If CKD is not recycled, there is a negative impact on the operating cost of the plant. Table IV-5 summarizes the capital and operating costs in terms of \$ per ton of clinker produced for different types of kilns. The capital and operating costs of the spray dryer include a baghouse, new stack and new ID (induced draft) fan. The capital and operating costs for the wet scrubber include new fans and a new stack as well as a new wastewater treatment facility.

Another installation was made in 1998 at Castle Cement's Ribblesdale (UK) facility (Castle Cement, 2004). Scrubber installation cost £5 million and operational costs are about £750,000 annually. Emissions from one unit were reduced by 90%.

Table IV-4 SO₂ Control Techniques Applicable to Cement Kilns (Miller, 2001)

SO ₂ reduction technique	Applicable to kiln type				Range of removal efficiency
	Long wet	Long dry	Preheater	Precalciner	
Process alterations	x	x	x	x	0-100%
Dry reagent injection			x	x	25-85%
Hot meal injection			x	x	0-30%
Spray dryer absorber		x	x	x	50-90%
Wet SO ₂ scrubber	x	x	x	x	80-95%

Table IV-5 Capital and operating costs of spray dryers and wet scrubbers applied to cement kilns (Young, 2002)

	Clinker capacity, tpy	Spray Dryer		Wet Scrubber	
		Capital Cost, \$/ton clinker	Annual Operating Cost, \$/ton clinker	Capital Cost, \$/ton clinker	Annual Operating Cost, \$/ton clinker
Small wet kiln	300,000	\$54.67	\$20.02	\$47.00	\$22.59
Medium wet kiln	600,000	\$38.17	\$14.09	\$32.67	\$17.58
Medium dry kiln	600,000	\$39.75	\$14.79	\$31.83	\$17.21
Large dry kiln	1,200,000	\$23.17	\$9.43	\$20.42	\$13.05
Medium preheater kiln	600,000	\$17.92	\$7.51	\$15.83	\$9.85
Medium precalciner kiln w/ bypass	600,000	\$25.17	\$10.20	\$19.33	\$11.42
Large preheater kiln	1,200,000	\$10.96	\$5.41	\$10.83	\$8.14

An alternative secondary control device for SO₂ was designed and applied as part of U.S. Department of Energy's Clean Coal Technology program. A co-project of Passamaquoddy Technology and Dragon Products Company in Thomaston, ME, the Passamaquoddy Technology Recovery Scrubber™ (Recovery Scrubber™) utilizes cement-kiln dust as a reagent for removing SO₂ from kiln exhaust gases (USDOE, 2001). Waste heat from the kiln is used to crystallize K₂SO₄, a saleable, fertilizer-grade by-product. The remaining cement kiln dust is returned to the kiln, significantly reducing particulate emissions, eliminating the need for removal of the dust to a landfill, and

reducing the requirement for raw materials by about 10 percent. Sulfur dioxide was reduced by 82 to 98.5%, depending on scrubber inlet SO₂ rates. In addition, NO_x was reduced by about 25% and VOCs by 70%. Capital costs for a Recovery ScrubberTM were estimated at about \$10.5 million in 1996 dollars, with operating and maintenance costs of \$150,000 per year and electricity costs of \$350,000 per year (787 kW at \$0.06/kW).

4.4.2. Nitrogen Oxides Control

Table 6 presents a summary of NO_x controls that are feasible for cement kilns, the range of potential NO_x reductions from applying these controls, the cost effectiveness of the controls, and effects on other emissions when using these controls.

Table IV-6 Summary of the Feasibility of NO_x Controls for Cement Kilns

NO_x Reduction Technique	Technical Feasibility	NO_x Reduction Potential (%)¹	Cost Effectiveness (\$/ton NO_x removed)	Effect on Other Emissions	Reference
Process Modifications	In full-scale use	0 - 30 [15]	3,100 - 8,800	Unknown	16
Low NO _x Burners w/ Indirect Firing	In full-scale use	0 – 20 [10]	5,800 - 8,100	Unknown	16
Low NO _x Burners w/ Indirect Firing and Mid-kiln Tire Injection	In full-scale use	[49]	1 - 1,800	Unknown	17
Mid-Kiln Injection of Fuel, Riser Duct Firing Calciners	In full-scale use	0 – 30 [15]	5,100 -11,500	May increase CO, SO; hydrocarbon emission	16
CemStar	Wet kilns	20 - 50 [20]	0-600	Unknown	17
Low NO _x Precalciner	Have been installed on several full-scale kilns - Offered by several different vendors.	30 – 40 [30]	2,700 - 3,600	May Increase emissions CO, SO ₂ , and/ or hydrocarbons	16
SNCR	May be applicable only on preheater or precalciner kilns - limited data	15 – 65 [45]	900 - 1,200	May Increase emissions CO, NH ₃ , and NH ₄ +salts (detached plume)	17
Biosolids Injection	May be applicable only on preheater or precalciner kilns - limited data	[50]	100-1,800	May Increase emissions CO, NH ₃ , and NH ₄ +salts (detached plume)	17

¹Values in brackets are the assumed NO_x reductions used to calculate the estimated cost effectiveness of each Technology.

4.4.3. PM_{2.5} Control

As discussed above, control of particulate matter in cement kilns is accomplished using baghouses and electrostatic precipitators. These processes are also used in electric utility generating units and industrial boilers. Capital and operating costs for fabric filters and ESPs as applied to cement kilns were computed by Young (2002) and are summarized in Table IV-7. The costs include the addition of a new fan.

Table IV-7 Capital and operating costs of baghouses and ESPs applied to cement kilns (Young, 2002)

	Clinker capacity, tpy	New ESP		New baghouse	
		Capital Cost, \$/ton clinker	Annual Operating Cost, \$/ton clinker	Capital Cost, \$/ton clinker	Annual Operating Cost, \$/ton clinker
Small wet kiln	300,000	\$14.00	\$3.35	\$16.67	\$3.81
Medium wet kiln	600,000	\$11.00	\$2.49	\$13.00	\$2.92
Medium dry kiln	600,000	\$10.50	\$2.54	\$12.00	\$2.78
Large dry kiln	1,200,000	\$7.33	\$1.51	\$8.67	\$1.96
Medium preheater kiln	600,000	\$4.33	\$1.03	\$5.17	\$1.17
Medium precalciner kiln w/ bypass	600,000	\$5.33	\$1.42	\$6.33	\$1.53
Large preheater kiln	1,200,000	\$3.33	\$0.74	\$4.00	\$0.90

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5. KRAFT PULP MILLS

5.1. Description of pulp and paper processes

Kraft pulping processes consists of wood preparation, pulping, pulp washing, oxygen delignification and/or bleaching of pulp and chemical recovery as illustrated in Figure V-1. Beginning with wood preparation, logs are debarked, ground into wood chips, and then screened to remove chips of unacceptable sizes. During the pulping process, the wood chips enter the digester where they are cooked with liquor and broken down into a pulp slurry. The pulp slurry is transferred to a blow tank while the spent liquor is sent to a flash tank. The pulp slurry then enters the pulp washing process where knots, shives, and short fibers are removed, spent cooking chemicals are recovered from the pulp slurry, and the pulp slurry is thickened for later processes. Next, the pulp enters the oxygen delignification process where the lignin content of the pulp is reduced to increase brightness of the pulp. The brightness of the pulp is further enhanced by bleaching, a multi step process that removes residual lignin by using chemicals to oxidize and dissolve the lignin compounds. Lastly, the chemical recovery process recovers the spent cooking liquor using the following methods: evaporation to reduce water content in spent liquor, combustion of concentrated spent liquor, and recovery of chemicals from

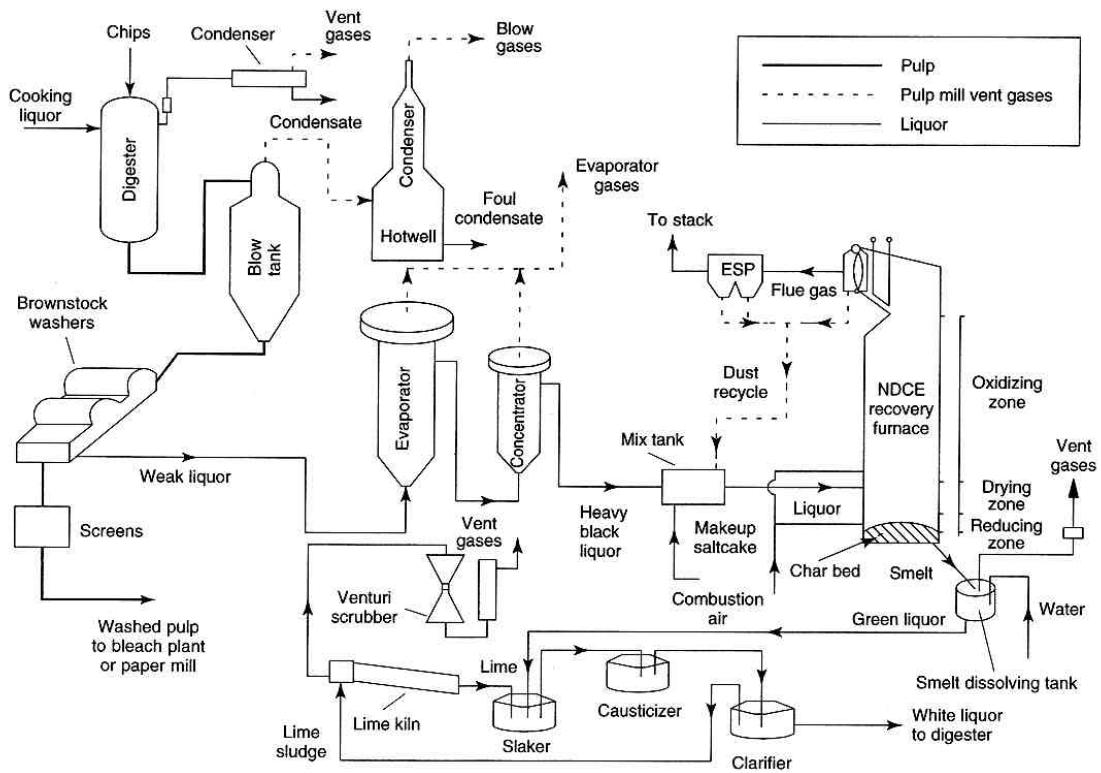


Figure 1. Schematic of the Kraft Pulping and Recovery Process (Someshwar and Pinkerton, 2000).

combustion products. The regeneration of lime, which is used for recovering sodium, is an additional step of the kraft chemical recovery process not found in the acid sulfite, mechanical, or semi chemical processes.

Acid Sulfite and semi chemical processes are very similar to the kraft process, however, the acid sulfite process differs from the kraft process in the type of cooking liquor used and the semi chemical process differs from the kraft process in the use of lower temperatures, more dilute cooking liquor or shorter cooking time, and mechanical disintegration. Mechanical pulping uses high-energy refining systems to produce pulp from chips and bleaching agents are used to decolorize lignin instead of removing lignin. (Someshwar and Pinkerton, 2000; Pinkerton, 2000).

5.2. Review of BART-Eligible Pulp and Paper facilities in the MANE-VU Region

There are 10 facilities with BART-Eligible industrial boilers in the MANE-VU region. Table III-2 contains a list of these sources based on a previous NESCAUM report (2003) and follow-up review by state permitting authorities.⁷ [*Editor's note: additional facilities may be added after NY and PA have completed their inventory*].

Table V-1 BART-eligible pulp and paper facilities.

State	Company/Facility	City/Town	Category
Maryland	WESTVACO FINE PAPERS	Luke	kraft pulp
Maine	Domtar - Pulp & Paper	Baileyville	kraft pulp
Maine	Fort James - OldTown	Old Town	kraft pulp
Maine	IP Androscoggin	Jay	kraft pulp
Maine	Lincoln Pulp and Paper	Lincoln	kraft pulp
Maine	Madison Paper	Madison	kraft pulp
Maine	Mead WestVaco	Rumford	kraft pulp
Maine	SD Warren - Somerset	Skowhegan	kraft pulp
Maine	SD Warren Co.	Westbrook	kraft pulp
New Hampshire	Pulp & Paper Mills (33007-00001-11)	Berlin	kraft pulp

5.3. Available Control Technologies

The pulp and paper production, consisting of chemical, mechanical, and semi chemical processes, has a number of potential sources of SO_x, NO_x, particulates, and VOC emissions (Pinkerton, 2000). The major chemical wood pulping processes are kraft, acid sulfite, and semi chemical pulping. Kraft pulping accounts for 80% of the

⁷ NESCAUM does not believe that there are any BART-eligible sources in the State of Vermont or any of the member Tribes in MANE-VU and thus we have not developed lists for these jurisdictions. In addition, Pennsylvania and the District of Columbia have developed BART-Eligible source lists following their own methodology and any identified sources are contained here and in the final list in Appendix A.

pulp produced in the U.S, mechanical and semi chemical pulping, for 10% and 6%, respectively and sulfite or soda chemical process accounts for the remaining pulping capacity (Someshwar and Pinkerton, 2000).

A variety of technologies exist for controlling emissions from pulp and paper facilities. Secondary control devices can be helpful in reducing emissions, and a number of them are available. Many facilities have found that significant emissions reductions can be achieved through process changes at the facility. Both secondary controls and process changes are discussed below, grouped by their targeted pollutant. When additional emissions reductions are possible, they are noted with the main (or targeted) pollutant. The sections below will describe the potential sources of significant SO_x, NO_x, particulates, and VOC emissions in the major pulping processes and the measures used to control them.

5.3.1. SO₂ Controls

In a kraft mill, SO₂ is a product of the incineration of black liquor in the recovery furnace; black liquor is made up of 3-5% sulfur by weight of dissolved solids. The majority of the sulfur exits the furnace in the smelt; however, typically less than 1% can be emitted as a gas or particulate, resulting in average SO₂ concentrations of 0-500 ppm in stack gases. Recovery furnace SO₂ emissions are a function of liquor properties such as sulfidity (sulfur-to-sodium ratio), heating value, and solids content; combustion air and liquor firing patterns; furnace design features; furnace load; auxiliary fuel use; and stack gas oxygen content. To reduce SO₂ emissions from the recovery furnace, the temperature in the lower furnace must be uniform. This has been achieved by optimizing liquor and combustion air properties and firing patterns. Reducing liquor sulfidity has also been used as a control strategy for SO₂ emissions. Flue gas desulfurization as an effective control strategy is uncertain due to the mostly low and unpredictable levels of SO₂ emitted.

In a lime kiln, SO₂ is produced from the combustion of fuel oil or non condensable gases (NCG). On average, lime kiln SO₂ emissions are very low due to the capture of SO₂ from the alkaline material inside the kiln and the venturi scrubber usually installed immediately after the kiln.

In semi chemical processes, only neutral sulfite semi chemical (NSSC) pulping emits SO₂ emissions as a result of the combustion of sulfur-containing semi chemical spent liquor in a fluidized bed combustor. Limited data shows an SO₂ emission factor for a fluidized bed combustor burning NSSC liquor as 1 lb SO₂/a.d. ton of pulp.

A major source of SO₂ in acid sulfite processes is from the digester and blow tank areas. During a hot blow, significant quantities of SO₂ can be released into the blow gases ranging from 10 to 70 pounds per ton of pulp. Using an alkaline solution to scrub the blow gases, 97% of SO₂ can be recovered and returned to the acid-preparation system. While this approach is possible using sodium and NH₃ bases, magnesium and calcium bases need slurry scrubbers deemed less practical. Scrubbing becomes

impractical when during a cold blow, only 4 to 20 pounds SO₂ per pulp are released into the blow gases.

SO₂ can also escape from acid bisulfite washers and screens which can result in uncontrolled emissions generally ranging from 1 to 4 lb SO₂/ton pulp but can get up to as much as 16 lb SO₂/ton pulp. The gases emitted from the washers and screens are hooded and then directed to a direct-contact scrubber where the SO₂ is scrubbed from the gases. (Someshwar and Pinkerton, 2000; Pinkerton, 2000).

5.3.2. NO_x Controls

NO_x is produced from the incineration of black liquor in the kraft recovery furnace with black liquor containing 0.05% to 0.25% nitrogen by weight of liquor solids content. Normal NO_x emissions from kraft recovery furnaces are less than 100 ppm. NO_x emissions are mainly a result of fuel NO_x since the maximum temperature in the recovery furnace is approximately 2400°F and the temperature required for formation of significant amounts of thermal NO_x is greater than 2800°F. NCASI studied the origins of NO_x emissions from kraft recovery furnaces and concluded that the two most important factors affecting NO_x emissions, in order of importance, were the black liquor nitrogen content and excess oxygen in the zone where most of the liquor combustion occurs. Since it is difficult to alter the liquor N content, the best approach to minimizing NO_x in recovery furnaces is staged-air combustion. Currently, most recovery furnaces already optimally use staged combustion and emit less than 100ppm NO_x.

NO_x is produced in the kraft lime kiln from the combustion of fossil fuels, such as natural gas and residual fuel oil. Due to the design of the lime kiln, SNCRs and SCRs are not viable NO_x reduction techniques. Installing Low-NO_x Burners (LNBS) is also not a practical NO_x reduction technique according to a BACT analysis conducted on a new lime kiln in 1997. The installation of LNBS had a negative influence on the efficiency, energy usage, and calcining capacity of the lime kiln. Hence, like the recovery furnace, combustion modification such as decreasing excess air is the best way to reduce NO_x emissions. However, since the mechanisms of NO_x formation and NO_x emission reduction are not completely known, NO_x reduction strategies should be considered on a case-by-case basis.

Some NO_x emissions result from the burning of stripper off gases (SOGs) with significant ammonia and methanol content and combustion of NCG in the kiln, thermal oxidizer, or boiler. When SOGs containing methanol and ammonia are incinerated, the ammonia could potentially oxidize to produce NO_x. NH₃ will oxidize to NO_x when injected into gases above 2000°F to 2200°F, reduce NO_x to N₂ when gas temperatures range from about 1600°F to 2200°F, and remain as NH₃ in temperatures below 1600°F. However, the degree of NH₃ conversion to NO_x and the expected baseline level of NO_x emissions from pulp process units burning NCG and SOGs are not known.

NO_x emissions are expected during combustion of liquor in recovery furnaces for both semi chemical and acid sulfite processes. (Pinkerton, 2000; Someshwar, 1999).

5.3.3. PM_{2.5} Controls

Measurable particulate emissions sources in a kraft mill are recovery furnaces, smelt-dissolving tanks, and lime kilns while fugitive particulate emissions sources are coal piles, paved and unpaved roads, bulk material handling such as lime, limestone, or starch, and wood handling. Particulate emissions from recovery furnaces are controlled by ESPs with particulate removal efficiencies of 90% in older units and 99% in newer units. Demister pads, packed towers or venturi scrubbers are used to achieve particulate emissions control in smelt-dissolving tanks, and venturi scrubbers and ESPs are used for control in lime kilns. Controlled mean particulate emission factors from smelt dissolving tank vents and kraft lime kilns are 0.13 lb/ton black liquor solids and 1.82 lb/ton of reburned lime product, respectively. Fugitive emissions are controlled by wetting; using chemical agents, building enclosures, and windscreens; paving or wetting roads; and modifying handling equipment.

In semi chemical processes, particulate emissions only become a concern when recovery furnaces are used. These emissions are controlled by using ESPs, wet ESPs or venturi scrubbers. In acid sulfite processes, the burning of both ammonium and magnesium base liquors will result in the release of particulate matter in the form of ammonium salts and magnesium oxide, respectively. The ammonium salts are removed when the flue gas exiting the absorption unit enters a series of fabric mesh pads called “candles.” The magnesium oxide particulates are removed using multiple cyclones, a series of 3 or 4 packed tower absorbers, and in addition, some mills use venturi scrubbers and/or a SO₂ scrubber. Controlled particulate emissions of ammonia salt particles are <0.5 gr/dscf @ 8% O₂ and for magnesium oxide, 0.05 to 0.1 gr/dscf correct to 8% O₂. (Someshwar and Pinkerton, 2000).

5.3.4. VOC Controls

VOC emissions sources in a kraft mill are recovery furnaces and lime kilns. In a recovery furnace, VOC emissions are produced from incomplete combustion or from the contact between the black liquor and flue gas where volatile material from the liquor can transfer to the flue gas. Factors that affect recovery-furnace VOC emissions are the level of excess air used and the degree of mixing achieved within the furnace. To lower recovery-furnace VOC emissions, the residence time, oxygen content, temperature, and level of turbulence in the furnace combustion zone must be increased. However, increasing these parameters will increase NO_x emissions.

VOC emissions from lime kilns are also produced from incomplete combustion. In addition, VOC emissions can be a result of VOCs entering the kiln with the liquid part of the lime mud and VOCs being present in the scrubber makeup water. These additional VOCs are then emitted into the flue gas when the lime mud is heated and the flue gas exiting the kiln strips the VOCs from the scrubber makeup water. VOC emissions from lime kilns tend to be small with the majority being methanol.

In semi chemical and acid sulfite pulping processes, VOC emissions are a product of incomplete combustion in the fluidized bed combustor or in a specialized recovery furnace. Semi chemical VOCs can also be introduced into the flue gas if flue gas comes

in contact with pulping liquor. VOCs from both semi chemical and acid sulfite pulping processes can enter the flue gas if the flue gas is able to strip organic compounds such as methanol from the scrubber makeup water. According to limited data, VOC emissions can significantly be reduced by improving combustion conditions and controlling liquor firing.

Mechanical pulping processes only emit VOCs and steam into the atmosphere. The VOCs in wood are emitted with the steam when wood undergoes cooking and refining processes. A study conducted by NCASI showed that VOC emission rates were proportional to steam emission rates. This data suggests that in order to decrease VOC emissions, the temperature in the exhaust gas must be reduced below the boiling point of water. (Someshwar and Pinkerton, 2000; Pinkerton, 2000).

5.4. Costs and availability

According to John Pinkerton at the National Council of the Paper Industry for Air and Stream Improvement (NCASI) (Pinkerton, 2004), pulp and paper industry representatives have been working with several engineering firms to evaluate to assess the costs and emission reduction potential of SO₂ and NO_x control technologies. Many of the technologies are candidates for evaluation as part of a BART site-specific engineering analysis. Particulate matter (PM) control strategies were also evaluated by NASCI. Information on applicability and cost is summarized in Tables V-2 through V-5 for Kraft Recovery Furnaces, Lime Kilns, Wood and Wood/Gas boilers and Wood/Coal and Wood/Oil boilers.

Information on the technologies referenced in the tables was collected by NASCI based on installation of processes or evaluation of these processes as part of New Source Review (NSR) Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER) analyses, state Reasonably Available Control Technology (RACT) evaluations in ozone non-attainment areas, the USEPA NO_x SIP Call, or for other reasons.

The range in costs and emission reductions reflects the fact that site-specific factors play a critical role in determining how cost-effective various technologies will be in practice. Existing facilities do not always adequate or appropriate space for new equipment, which adds uncertainty to the capital and operating cost, as well as to the achievable emissions reductions. Hence the range of costs cited in the tables.

Table V-2 Reduction of NO_x, SO₂ and PM in Kraft Recovery Furnaces (Pinkerton, 2004).

	SO ₂	NO _x	PM
Factors affecting emissions	Type of furnace, operating practices, black liquor solids concentration.	Type of furnace, operating practices, nitrogen content of black liquor, black liquor solids concentration.	Type of furnace, ESP efficiency
Current Emission Levels	~0 to 300 ppm	40 to 130 ppm	0.01 – 0.1 gr/dscf
National Emission Standards	none	none	1978 NSPS, 2001 MACT Existing Source – 0.044 gr/dscf. New source MACT is 0.015 gr/dscf
Recent BACT Determinations	50 to 300 ppm	75 to 150 ppm	0.021 to 0.044 gr/dscf
Current Installed End of Pipe Control Technologies	none	none	ESPs
Control Options	Optimize, on site-specific basis, liquor solids and operating practices; install SO ₂ scrubber	Staged combustion practices (very site-specific)	Larger ESPs
Applicability of Control Option and Potential Emission Reductions	Scrubbing possible on some units to reduce SO ₂ to as low as 10 ppm. Some units have emissions this low or lower at present.	SNCR and SCR not demonstrated as technically feasible.	Larger ESP possible on some units, although retrofit costs highly site-specific. Depending on current ESP design and condition, replacement or expansion of existing ESP can be considered
Cost of Option	Capital \$8 million (1.7 MMlb/day BLS DCE unit; \$12.8 million (3.7 MMlb/day BLS NDCE unit); Operating costs of \$1.1 to \$1.3 million (1.7 MMlb/day unit), or \$1.6 to 1.8 million/yr (3.7 MMlb/day unit). Lower operating costs are for achieving 50 ppm; higher for achieving 10 ppm. Costs are very site-specific.		Replacement of ESP to achieve 0.015 gr/dscf PM emissions: for a 3.7 MMlb BLS/day NDCE furnace - Capital \$29.3 million; operating \$1.9 million/yr; for a 1.7 MMlb BLS/day DCE unit: \$18.4 million capital; \$1.2 million/yr operating. Costs are very site-specific.

Table V-3 Reduction of NO_x, SO₂ and PM in Lime Kilns (Pinkerton, 2004).

	SO₂	NO_x	PM
Factors affecting emissions	Emissions are minimal due to alkaline nature of lime in kiln	Type of fuel (gas vs. oil), operating temperatures, nitrogen content of oil and oxygen availability in flame zone, burning NCGs	Type of control device and control device efficiency
Current Emission Levels	~0 to 20 ppm	0.05 to 0.4 lb/10 ⁶ Btu heat input	0.01 – 0.2 gr/dscf
National Emission Standards	none	none	1978 NSPS – 0.067/0.13 gr/dscf (gas/oil); 2001 MACT Existing Source – 0.064 gr/dscf. New source MACT is 0.01 gr/dscf
Recent BACT Determinations	30 to 80 ppm	100 to 220 ppm	0.015 to 0.13 gr/dscf
Current Installed Control Technologies	none	none	Wet scrubbers, ESPs
Control Options	Wet scrubber with supplemental caustic control	none	Replace wet scrubber with ESP
Applicability of Control Option and Potential Emission Reductions			ESPs have higher removal efficiencies than wet scrubbers; all lime kilns installed in last ten years have ESPs rather than scrubbers. Average ESP emissions are on the order of 0.01 gr/dscf.
Cost of Option			Replacement of scrubber with ESP to achieve 0.01 gr/dscf PM emissions: for a 270 ton CaO/day kiln - \$3.4 million; operating \$0.2 million/yr.

Table V-4 Reduction of NO_x, SO₂ and PM in Wood and Wood/Gas-Fired Boilers (Pinkerton, 2004).

	SO ₂	NO _x	PM
Factors affecting emissions	Sulfur content of wood minimal	Type of boiler, wood nitrogen and moisture content, operating practices	Wood ash content, control device efficiency, operating practices
Current Emission Levels	0.025 lb/10 ⁶ Btu is AP-42 emission factor	0.15 to 0.3 lb/10 ⁶ Btu	0.05 to 0.6 lb/10 ⁶ Btu
National Emission Standards	none	Subpart Db NSPS- none if gas capacity factor limited to 10% or less; gas capacity factor over 10% - 0.3 lb/10 ⁶ BTU except 0.2 lb/10 ⁶ BTU for new/reconstructed units after 1997	Subpart D, Db, Dc NSPS – 0.1 lb/10 ⁶ Btu; final boiler MACT limit – 0.07 lb/10 ⁶ Btu for existing, 0.025 lb/10 ⁶ Btu for new solid fuel boilers
Recent BACT Determinations	0.01 to 0.045 lb/10 ⁶ Btu	0.25 to 0.3 lb/10 ⁶ Btu	0.02 to 0.1 lb/10 ⁶ Btu
Current Installed Control Technologies	none	SNCR for base loaded boilers	Mechanical collectors, wet scrubbers, gravel bed filters, ESPs, fabric filters
Control Options	none	SNCR for base loaded boilers	Replace wet scrubber with an ESP
Applicability of Control Option and Potential Emission Reductions		SNCR has been installed on a few new wood boilers to achieve NO _x reductions in the 20 to 50% range. SNCR not appropriate for boilers with high load swings. SCR has not been applied.	ESPs in use on many wood boilers. Emission levels as low as 0.02 lb/10 ⁶ Btu possible. Retrofit costs highly site-specific.
Cost of Option		Installing SNCR to achieve 0.15 lb/10 ⁶ Btu NO _x emissions on a 300,000 pph wood boiler: Capital \$1.5 million; operating \$0.1 million/yr	Installing ESP to achieve 0.04 lb/10 ⁶ Btu PM emissions on a 300,000 pph wood boiler: Capital \$21.3 million; operating \$1.4 million/yr. Costs to achieve a 0.065 lb/10 ⁶ standard range from \$18.7 million to \$5.1 capital, \$900,000 to \$77,000 operating—highly site-specific
Control Option		Methane de-NO _x Reburn	
Applicability of Control Option and Potential Emission Reductions		Has been applied to one boiler burning wood, gas, and sludge. Involves natural gas injection and flue gas recirculation in stoker-type boilers only. NO _x reduction reported to be 40 to 50% in boilers burning high nitrogen content fuels.	
Cost of Option		Capital costs unavailable. Lower operating costs claimed due to increased boiler efficiency.	

Table V-5 Reduction of NO_x, SO₂ and PM in Wood/Coal and Wood/Oil-Fired Boilers (Pinkerton, 2004).

	SO ₂	NO _x	PM
Factors affecting emissions	Coal/oil sulfur content, ratio of wood to coal/oil	Type of boiler, coal/oil nitrogen content, wood nitrogen and moisture content, ratio of wood to coal/oil	Wood/coal/oil ash content, oil S level, control device efficiency
Current Emission Levels	Depends on fuel mix and coal/oil S content	0.25 to 0.7 lb/10 ⁶ Btu	0.03 to 0.3 lb/10 ⁶ Btu
National Emission Standards	Subpart D NSPS limits SO ₂ to 1.2/0.8 lb/10 ⁶ Btu (coal/oil); Subparts Db and Dc require percent reduction (except for very small boilers or those with low coal capacity factors) or use of very low S oil	Revised 1998 NSPS has 0.2 lb/10 ⁶ Btu limit for boilers over 100 x 10 ⁶ Btu/hr for all fossil fuels, limit applies if annual fossil fuel capacity factor exceeds 10%. Prior NO _x limits were fuel-type dependent and ranged from 0.3 to 0.7 lb/10 ⁶ Btu for oil and coal.	Subpart D, Db, Dc NSPS – 0.1 lb/10 ⁶ Btu unless annual wood capacity factor is less than 10%; final boiler MACT limit – 0.07 lb/10 ⁶ Btu for existing, 0.025 lb/10 ⁶ Btu for new solid fuel boilers
Recent BACT Determinations	0.3 to 0.5 lb/10 ⁶ Btu	0.3 to 0.7 lb/10 ⁶ Btu	0.03 to 0.1 lb/10 ⁶ Btu
Current Installed Control Technologies	Alkaline scrubbing	SNCR for base loaded boilers, FGR, Low NO _x burners	Mechanical collectors, wet scrubbers, gravel bed filters, ESPs, fabric filters
Control Options	Alkaline scrubbing	Low NO _x burners	Replace wet scrubber with an ESP
Applicability of Control Option and Potential Emission Reductions	Generally applicable; reductions up to 90% possible	This option only available to pulverized coal/stoker boilers or oil/wood units. NO _x reductions in the 20 to 50% range can be achieved for the coal or wood contribution to total NO _x .	ESPs in use on many wood/coal and wood/oil boilers. Emission levels as low as 0.02 lb/10 ⁶ Btu possible. Retrofit costs highly site-specific.
Cost of Option	Capital cost for scrubber installation following and ESP on a 300,000 pph wood/coal boiler - \$7.4 to 8.2 million. Annual operating cost for 50% removal \$1.0 million, \$1.5 to 2.0 million for 90% removal.	Installing low NO _x burners to achieve a 0.3 lb/10 ⁶ Btu level on a 300,000 pph wood/pulverized coal boiler: Capital \$2.9 million; operating \$0.15 million/yr. Retrofit costs site-specific.	Remove existing control device and install ESP to achieve 0.04 lb/10 ⁶ Btu PM emissions on a 300,000 pph wood/coal boiler: Capital \$5.1 to 20.5 million; operating \$70,000 to 1.2 million/yr. Retrofit costs site-specific.
Control Option	Lower S content coal/oil; gas	SNCR for base loaded boilers	
Applicability of Control Option and Potential Emission Reductions	Generally applicable	Limited NO _x reductions possible, in the 20 to 40% range. SNCR not appropriate for boilers with high load swings.	
Cost of Option	Dependent on fuel prices	Capital cost of \$1.5 million for a 300,000 pph wood boiler with limited coal or oil use; operating cost of \$0.15 million/yr. Retrofit costs site-specific.	

References

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6. CONCLUSION

As states prepare to conduct BART determinations for their eligible facilities, preliminary information has been collected on the availability, costs and efficiencies of a variety of technology options. Depending on the requirements contained in the final BART regulations, anticipated for April 2005, states will have to decide what level of cost and what degree of visibility improvement is considered reasonable before completing BART determinations. MANE-VU has reviewed technology options for four of the 26 BART-eligible source categories. For EGUs, industrial boilers, cement plants and paper and pulp facilities, we present typical control options and costs. Facility specific reviews will be needed to determine specific controls and costs for each BART-Eligible source in the region.

6.1. EGUs

The presumptive level of control for previously uncontrolled EGU boilers as included in the proposed BART regulations include FGD (Scrubber) technology with an SO₂ control efficiency of approximately 95 percent. Chapter 2 points out that the average scrubber operating today does not achieve this level of control (existing scrubbers have a range of efficiencies between 30 and 97 percent); however, new installations are achieving rates even higher than 95 percent removal. Additional measures which can be considered for SO₂ control include the use of low-sulfur coal (compliance coal) (typically XX percent SO₂ reduction), spray dry adsorption (60-95 percent removal), dry scrubbing (40-60 percent removal) or circular fluidized-bed adsorption technology (80-98 percent removal). SO₂ control is highly cost effective with operational costs in the \$100-200 per ton range.

NO_x control technologies can be grouped into combustion controls (including low-NO_x burners (LNBs), overfire air, off-stoichiometric firing, selective or biased burner firing, reburning, burners-out-of-service, and air staging) and post-combustion controls (include selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) processes). Combustion controls result in typical NO_x reductions of 15 to 60 percent, depending on the specific boiler and combination of controls. SCR achieves a 90-95 percent reduction whereas SNCR achieves 25-50 percent reduction in NO_x. Costs for NO_x removal range from \$200-500/ton for some of the low yield techniques to \$1000 to \$1500/ton for SCR with 90-95 percent removal efficiency.

Particulate matter (PM) control technologies include electrostatic precipitators (ESPs), fabric filters (FFs) (also called “baghouses”), and particulate scrubbers (PS). These technologies typically achieve greater than 95 percent removal of total particulate mass with over 80 percent removal of PM smaller than 0.3 um (with the exception of particulate scrubbers which achieve only 30-85 percent removal for this smaller size fraction). Mechanical collectors have even lower trapping efficiencies. PM controls are in place on virtually all EGUs already, hence the issue that will be faced in conducting BART determinations is how these existing controls will interface with proposed controls for other pollutants.

6.2. Industrial Boilers

For industrial boilers, many of the same control technologies for EGUs are applicable to this source category including: low sulfur coal, wet and dry FGD (or scrubber) technology for SO₂, combustion modifications and SCR and SNCR technology for NO_x, and ESP, fabric filter and wet scrubbing techniques for PM. However, industrial boilers have a wider range of sizes than EGUs and often operate over a wider range of capacities. Thus cost estimates for the same technologies will generally range, depending on the capacity of the boiler and typical operating conditions. High end cost estimates for NO_x removal can be over \$10,000/ton.

6.3. Cement Kilns

Designing a system of emission controls for cement kilns are somewhat more complicated given that the quality of clinker produced in a kiln varies with characteristics of the combustion, it is possible to combine combustion technologies with post-combustion technologies for cement kilns in some cases and it is also possible to combine multiple combustion technologies on cement kilns. As a result, primary controls need to be selected carefully taking engineering and cost decisions into account for each specific kiln.

Control options for SO₂ include in-process removal, process changes (e.g. combustion optimization, flame shape adjustment or raw material changes), and the use of wet or dry scrubbers. For NO_x, both process modifications (e.g. combustion modifications, low-NO_x burners, secondary combustion or staged combustion) as well as post combustion controls need to be selected carefully. Particulate control devices for cement plants must be able to clean gases with fairly high dust loading given that the concentrations of particles in the exhaust can be several times higher than in a coal-fired power plant. In addition, PM technologies are affected by the presence of corrosive gases which can be reduced most effectively in a roller mill. While fabric filters (baghouses) and electrostatic precipitators are still the most common means of PM control at cement plants, a number of novel techniques and procedures are used to deal with the unique issues face by cement kilns.

Costs for SO₂ controls at cement kilns will vary widely depending on control options selected and process variables (e.g. whether material is recycled in the control process). Capital cost for typical wet/dry scrubbing post-combustion controls have been estimated in the \$10-50/ton of clinker produced with operating costs in the \$5-20/ton of clinker range. PM controls are similarly estimated in the \$3-15/ton of clinker range for capital costs and \$0-30/ton clinker for operating costs on an annual basis. NO_x has not been estimated on a per ton of clinker basis, but estimates vary between 0 and \$10,000/ton of NO_x reduced.

6.4. Pulp Mills

Paper and pulp facilities have perhaps the widest range of operational configurations and thus possibilities for reducing pollutant emissions. A variety of

technologies exist for controlling emissions from pulp and paper facilities. Secondary control devices can be helpful in reducing emissions for some processes, and a number of them are available. Many facilities have found that significant emissions reductions can be achieved through process changes at the facility. Both secondary controls and process changes are presented as options.

For Kraft mill recovery furnaces, combustion modifications can be effective at reducing SO₂, NO_x, and VOCs. Reducing the liquor sulfidity can also help reduce SO₂ emissions. PM control for recovery furnaces is typically achieved through the use of ESPs or wet ESPs.

Lime kilns are also a significant source of visibility impairing pollutants; however, there are fewer options for effectively reducing SO₂ emissions. Combustion modifications can reduce NO_x and VOC emissions and Venturi scrubbers and ESPs are commonly used for PM control.

Demister pads, packed towers and Venturi scrubbers are used to reduce PM emissions from smelt dissolving tanks.

The range in costs and emission reductions reflects the fact that site-specific factors play a critical role in determining how cost-effective various technologies will be in practice. Existing facilities do not always have adequate or appropriate space for new equipment, which adds uncertainty to the capital and operating cost, as well as to the achievable emissions reductions. Hence a wide range of costs have been cited.

Appendix A: BART-Eligible Facilities in the MANE-VU Region

NESCAUM has conducted two previous studies to identify a comprehensive list of BART-eligible sources in the MANE-VU region (NESCAUM, 2001; NESCAUM, 2003). These studies have been carefully reviewed by permitting authorities in each of the MANE-VU jurisdictions and the sources listed in Table A-1 represent the list of sources identified through that process. Non-EGU sources for Pennsylvania and New York are still pending and should be available for inclusion in the Final Report.

Table A-1 BART-Eligible Facilities in the MANE-VU Region

State	Facility	Town/City	BART Category
Connecticut	Middletown		EGU
Connecticut	Montville		EGU
Connecticut	Norwalk Harbor		EGU
Connecticut	PSEG Power Connecticut LLC- Bridgeport Harbor		EGU
Connecticut	PSEG Power Connecticut LLC-New Haven Harbor		EGU
Connecticut	SPRAGUE PAPERBOARD INC	Versailles	boilers
Connecticut	PFIZER INC	Groton	chemical plant
Delaware	Edge Moor		EGU
Delaware	Indian River		EGU
Delaware	Mckee Run		EGU
Delaware	Citisteel	Claymont	iron and steel
Delaware	DuPont Edge Moor	Edge Moor	chemical plant
Delaware	Reichhold	Cheswold	chemical plant
Delaware	Motiva	Delaware City	petrol. storage
District of Columbia	Benning (PEPCO)	District of Columbia	EGU
Massachusetts	Brayton Point		EGU
Massachusetts	Canal		EGU
Massachusetts	Cleary Flood		EGU
Massachusetts	Braintree Electric		EGU
Massachusetts	Mystic		EGU
Massachusetts	New Boston		EGU
Massachusetts	Salem Harbor		EGU
Massachusetts	EASTMAN GELATINE CORP	Peabody	chemical plant
Massachusetts	GENERAL ELECTRIC AIR (GE Aircraft Engines)	Lynn	boilers
Massachusetts	TRIGEN BOSTON ENERGY- KNEELAND STATION	Boston	boilers

Massachusetts	GULF OIL LP CHELSEA	Chelsea	petrol. storage
Massachusetts	REFUSE ENERGY SYSTEM COMPANY	Saugus	incinerator
Massachusetts	SOLUTIA INC. (MONSANTO CO.)	Springfield	boilers
Massachusetts	EXXON EVERETT TERMIN (EXXON EVERETT MARKETING TERMINAL #240	Everett	petrol. storage
Massachusetts	GLOBAL PETROLEUM CORP.	Revere	petrol. storage
Massachusetts	HARVARD UNIVERSITY CAMBRIDGE	Cambridge	boilers
Maryland	C P Crane		EGU
Maryland	Chalk Point		EGU
Maryland	Dickerson		EGU
Maryland	Herbert A Wagner		EGU
Maryland	Morgantown		EGU
Maryland	Vienna		EGU
Maryland	EASTALCO ALUMINUM	Frederick	aluminum ore
Maryland	ST. LAWERENCE CEMENT(formerly Independent Cement)	Hagerstown	portland cement
Maryland	WESTVACO FINE PAPERS	Luke	kraft pulp
Maryland	METTIKI COAL CORPORATION	Oakland	coal cleaning
Maine	William F Wyman		EGU
Maine	Domtar - Pulp & Paper	Baileyville	kraft pulp
Maine	Dragon Products	Thomaston	portland cement
Maine	Fort James - OldTown	Old Town	kraft pulp
Maine	International Paper - Bucksport	Bucksport	boilers
Maine	IP Androscoggin	Jay	kraft pulp
Maine	Katadhin - Mill W.	Millinocket	boilers
Maine	Lincoln Pulp and Paper	Lincoln	kraft pulp
Maine	Madison Paper	Madison	kraft pulp
Maine	Mead WestVaco	Rumford	kraft pulp
Maine	SD Warren - Somerset	Skowhegan	kraft pulp
Maine	SD Warren Co.	Westbrook	kraft pulp
Maine	Gulf Oil - S Portland	South Portland	petrol. storage
New Hampshire	Merrimack		EGU
New Hampshire	Newington		EGU
New Hampshire	Annheuser-Busch	Merrimack	boilers
New Hampshire	Pulp & Paper Mills (33007-00001-11)	Berlin	kraft pulp
New Hampshire	Dartmouth College	Hanover	boilers
New Jersey	Hudson		EGU
New Jersey	CHEVRON PRODUCTS CO 18058	Perth Amboy	petrol. refinery
New Jersey	AMERADA HESS CORP PORT READING 17996	Woodbridge	petrol. refinery
New Jersey	BAYWAY REFINING CO 41805	Linden	petrol. refinery
New Jersey	COASTAL EAGLE POINT OIL COMPANY 55781	Westville	petrol. refinery
New Jersey	COLORITE SPECIALTY RESINS 45940	Burlington	chemical plant

New Jersey	GATX TERMINALS CORP CARTERET FACILITY 18010	Carteret	petrol. storage
New Jersey	GENERAL CHEMICAL CORP 07369	Newark	acid, sulfur, charcoal
New Jersey	GREEN TREE CHEMICAL TECHNOLOGIES INC 18185	Parlin	chemical plant
New Jersey	Griffin Pipe Products (45954)	Florence	iron and steel
New Jersey	Infineum USA LP- Bayway Chemical Plant (41767)	Linden	chemical plant
New Jersey	SHELL OIL PRODUCTS CO SEWAREN PLANT 18051	Sewaren	petrol. storage
New York	Arthur Kill		EGU
New York	Astoria		EGU
New York	Bowline Point		EGU
New York	Charles Poletti		EGU
New York	Danskammer		EGU
New York	E F Barrett		EGU
New York	Lovett		EGU
New York	Northport		EGU
New York	Oswego		EGU
New York	Ravenswood		EGU
New York	Roseton		EGU
New York	Samuel A Carlson Generating Station		EGU
New York	Consolidated Edison's 59th St Station		EGU
Pennsylvania	Bruce Mansfield		EGU
Pennsylvania	Brunner Island		EGU
Pennsylvania	Cheswick		EGU
Pennsylvania	Conemaugh		EGU
Pennsylvania	Eddystone		EGU
Pennsylvania	Hatfield's Ferry		EGU
Pennsylvania	Homer City		EGU
Pennsylvania	Keystone		EGU
Pennsylvania	Martins Creek		EGU
Pennsylvania	Mitchell		EGU
Pennsylvania	Montour		EGU
Pennsylvania	New Castle		EGU
Pennsylvania	Portland		EGU
Pennsylvania	Warren		EGU
Rhode Island	BROWN UNIVERSITY	Providence	boilers
Rhode Island	Clariant Corp.	Coventry	chemical plant