TECHNICAL SUPPORT DOCUMENT

for

CONTROL OF NITROGEN OXIDE EMISSIONS

from

Industrial Boilers and Electrical Generating Unit Boilers
Process Heaters
Cement Kilns
Lime Kilns
Reheat, Annealing, and Galvanizing Furnaces used at Iron and Steel Plants
Glass Melting Furnaces
Aluminum Melting Furnaces

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for

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Abbreviations Used in this Technical Support Document

Term	Meaning
ACT	Alternative Controls Technique document
ALAPCO	Association of Local Air Pollution Control Officials
API	American Petroleum Institute
ATP	Andover Technology Partners
BART	Best Available Retrofit TechnologyBubbling Bed
BB	Bubbling Fluidized Bed Combustor
BFBC	Blast Furnace Gas
BFG	BioSolids Injection
BSI	Burners Out of Service
BOOS	Clean Air Interstate Rule
CAIR	Clean Air Markets Division
CAMD	Combined Cycle Gas Turbine
CCGT	Continuous Emission Monitoring System
CEMS	Circulating Fluidized Bed
CFB	Circulating Fluidized Bed Combustor
CFBC	Carbon Monoxide
CO	Carbon Dioxide
CO_2	Coke Oven Gas
COG	Combined Pollutant Standards
CPS	Capital Recovery Factor
CRF	Combustion Tuning
CT	Direct Flame Impingement
DFI	Electric Generating Unit
EGU	Fluidized Catalytic Cracking Units
FCCU	Fluidized Bed Combustion
FBC	Flue Gas Recirculation
FGR	Hydrocarbon
HC	Hydrogen Cyanide
HCN	Heat Recovery Steam Generator
HRSG	Internal Combustion Engine
ICE	ICF Consulting
ICF	Industrial Commercial Institutional
ICI	Illinois EPA
IEPA	Lake Area Directors Consortium
LADCO	Low Excess Air
LEA	Low NOx Burner
LNB	LNB with OFA
LNBO	Low NOx Concentric Firing System 1 or 2, or 3
LNC1, 2, 3	Loss of Ignition - a measure of unburned fuel
LOI	Lean Premixed Combustion
LPC	Lean Premixed
LPM	Multiple Burner Watertube
MBW	Mechanical Draft

MD	Medium
Med.	million
mm or MM	million Btu
mmBtu or MMBtu	
MPS	Multi-Pollutant Standard
MW	Megawatts
ND	Natural Draft
NESCAUM	Northeast States for Coordinated Air Use Management
NG	Natural Gas
NH_3	ammonia
NH_4OH	ammonium hydroxide
NH_2CONH_2	aqueous urea
NOx	Oxides of Nitrogen, a pollutant including the gases NO and NO_2
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NSPS	New Source Performance Standards(Promulgated Under 40 CFR60)
OAQPS	Office of Air Quality Planning and Standards, USEPA
OC	Oxy-combustion
OEAS	Oxygen Enriched Air Staging
OFA	Over fire air
OH	Hydroxide
OT	Oxygen Trim
OTC	Ozone Transport Commission
OTR	Ozone Transport Region
PC	Pulverized Coal
ppm	Parts per million
PRB	Powder River Basin
PRH	Process Heater
RACT	Reasonably Available Control Technology
RAP	Reduced Air Preheat
REACH	Reduced Emissions and Advanced Combustion Hardware
Ref.	Reference
RFG	Refinery Fuel Gas
ROFA	Rotating Overfire Air
SCA	Staged Combustion Air
SCR	Selective Catalytic Reduction
SDA	Spray Drier Absorber
SI	Steam Injection
SIP	State Implementation Plan
SIP Call	The EPA's announced request for SIP's from certain jurisdictions
SNCR	Selective Non Catalytic Reduction
SO_2	Sulfur Dioxide
SOFA	Separated Overfire Air
STAPPA	State and Territorial Air Pollution Program Administrators
TSD	Technical Support Document

ULNB	Ultra Low NOx Burner
USEPA	U.S. Environmental Protection Agency
WI	Water Injection
Wt%	Weight percent

1. The Formation and Control of NOx

Oxides of Nitrogen (NOx) include both nitric oxide (NO) and nitrogen dioxide (NO_2). They are formed in the combustion of fuel with air.

This section covers the general principles of how NOx is formed and the factors that affect emissions of NOx. Discussions that are particular to the formation of NOx and the methods of controlling NOx for specific source types will be discussed in later sections on the specific source categories.

1.1 NOx Formation

NOx is formed when nitrogen present in the air, fuel, or in a process feedstock combines with oxygen in the combustion air at high temperatures in the flame. The primary form of NOx is nitric oxide (NO), but in some cases significant amounts of NO_2 are formed. NOx is formed when atmospheric nitrogen combines with oxygen (thermal NOx) or fuel bound nitrogen compounds combines with oxygen (fuel NOx). The third and less important source of nitric oxide (called prompt NOx) is formed when atmospheric oxygen reacts with hydrocarbon radicals derived from fuel and the resultant nitrogen oxide precursors rapidly change to nitric oxide at lower temperatures. Prompt NOx is generally minor compared to overall amount of NOx generated during combustion, but becomes important when NOx emissions are reduced to extremely low levels. Nitrogen oxides emissions from fired processes are typically 90-95% NO with the balance NO_2. However once the flue gas leaves the stack, NO is eventually oxidized in the atmosphere to form NO_2. This is why, when NOx emissions are described on a mass basis (ie., lb/MMBtu or tons per year), it is assumed that the NOx is entirely in the form of NO_2 (although most is actually in the form of NO when it leaves the stack). A detailed description of each source of NOx formation is described below:

1.1.1 Thermal NOx

Thermal NOx results from the oxidation of atmospheric nitrogen in the high temperature region of the combustion system. The mechanisms of NOx formation in combustion are very complex. It is believed that oxygen radicals formed during combustion attack atmospheric nitrogen molecule to produce NO and N radicals first. N radicals then combine with oxygen molecule to produce more NO and oxygen radicals. Nitrogen radicals also combine with OH radicals to produce NO.

Experimental measurements of thermal NOx formation have shown that the NO concentration is exponentially dependent on temperature and is proportional to nitrogen concentration in the flame, the square root of oxygen concentration in the flame, and the gas residence time. Thus, NO formation is approximated by the following equation:

$$[NO] = ke^{-K/T}[N_2][O_2]^{1/2}t$$

Where:

[ ] are mole fractions
K and k are reaction constants
T is temperature
t is residence time

Significant levels of NOx are usually formed above 2200°F under oxidizing conditions. Higher heat release rate and preheated combustion air increase the peak temperature of the flame and contribute to higher baseline NOx levels. Amongst coal-fired boilers, cyclone boilers typically have higher conversion of nitrogen to NOx because they operate at higher temperature compared to other types of boilers.

1.1.2 Fuel NOx

Fuel NOx results from the oxidation of fuel bound nitrogen. Higher nitrogen content of fuel will lead to higher NOx emissions, but the conversion to fuel NOx typically diminishes with increasing nitrogen concentration. It is believed that fuel bound nitrogen compounds such as pyridine, picoline, nicotine, and quinoline rapidly decompose to low molecular weight compounds, such as HCN and which then decay to NO and nitrogen (N_2). During combustion, the nitrogen bound in the fuel is released as a free radical and ultimately forms free N_2, or NO. It seems that the oxidation of fuel-bound nitrogen compounds to NO is rapid and the reaction system cannot be quenched as it can be for thermal NOx.

In stoichiometric or fuel-lean situations, the intermediates will generally react to form NO over N_2, where as in fuel-rich systems, there is evidence that the formation of N_2 is competitive with the formation of NO. Studies have also shown that under pyrolytic conditions, about 65% of the fuel nitrogen remained in the coal after heating to 750°C (1380°F), but only 10 percent remained at 1320°C (2400°F). This suggests that the formation of NOx may depend upon the availability of oxygen to react with the nitrogen during coal devolitization and the initial stages of combustion. If the mixture is fuel-rich, the formation of N_2 may compete with the formation of NO, thus reducing NOx formation.

Fuel NOx can contribute as much as 50% of total emissions when combusting oil and as much as 80% when combusting coal. Generally, about 20-30% fuel-bound nitrogen is converted to NO. As discussed above, conversion of fuel-bound nitrogen is strongly dependent on the fuel/air stoichiometry, but is relatively independent of variations in combustion zone temperature.

For industrial manufacturing processes that heat a feedstock (such as glass manufacturing), some feedstock material may contain some level of nitrogen. This nitrogen will partially oxidize to form NOx. The degree to which feedstock nitrogen oxidizes to form NOx will depend upon the form of the nitrogen in the feedstock and the specific conditions (temperature, oxygen concentration, etc.) that the feedstock material is exposed to.

1.1.3 Prompt NOx

Prompt NOx is attributed to the reaction of atmospheric nitrogen, N_2, with hydrocarbon radicals such as CH and CH_2 derived from fuel. It is generally believed that the principal product of the initial reaction is hydrogen cyanide (HCN) or CN radicals. The HCN radical is further reduced to form NO and other nitrogen oxides. As opposed to the slower thermal NOx formation, prompt NOx formation is rapid and it is not possible to quench prompt NOx formation in the manner by which thermal NOx formation is quenched.

Experiments show that maximum prompt NOx is reached on the fuel-rich side of the stoichiometry. On the fuel-lean side of the stoichiometry, there are fewer free hydrocarbon fragments (CH, CH_2 etc.) which can react with atmospheric nitrogen to form HCN, the precursor to prompt NOx. With increasing fuel-lean conditions, an increasing amount of HCN is formed, creating more NOx. However, above an equivalence ratio of about 1.4, there are not enough O radicals to react with HCN, so NO levels decrease. Prompt NOx is most significant for gas-fired diffusion flame combustion, where CH_i fragments are readily available and the contribution of fuel NOx to total NOx is negligible.

1.2 Controlling NOx emissions

NOx emissions are controlled by either:

- Using methods to limit the formation of NOx
- Using methods to reduce or capture the NOx that has been formed

1.2.1 Limiting NOx Formation – Combustion Controls

Because NOx is formed during combustion and heating, the methods used to control NOx formation are categorized as combustion controls. Using a low nitrogen fuel will help reduce NOx formation, providing other combustion parameters are not significantly affected. However, in fuel-air combustion, there are a wide range of technologies to limit the formation of NOx in specific facilities, including low NOx burners, overfire air, etc. All of these technologies use one or more of three general approaches to minimize NOx formation:

> *Air staging* achieves much of the combustion of fuel in a high-temperature, fuel-rich zone that is followed by a lower temperature zone with limited excess oxygen where fuel burn-out is completed. In the fuel-rich zone, fuel nitrogen is released as molecular nitrogen. In the lower temperature zone with excess oxygen, the temperature is maintained low enough and excess oxygen is minimized to limit the formation of thermal NOx while the fuel is burned out as efficiently as possible. Air staging is accomplished within several NOx control technologies, such as Low NOx Burners (LNB), Burners Out of Service (BOOS), Overfire Air (OFA), and others that will be described in detail later.
>
> *Fuel staging* follows the primary combustion zone (which may use air staging or other methods) with a fuel-rich zone that reduces the NOx formed in the primary combustion zone to molecular nitrogen. The fuel-rich zone is followed by an oxygen-rich zone that allows fuel burnout at lower temperatures, minimizing reformation of NOx. Fuel staging

technologies include reburning and gas pods on gas-fired burners.

Lean premixed combustion is used with volatile fuels that are low in nitrogen content and inherently have low fuel NOx formation, such as natural gas. In lean premixed combustion the fuel and air are premixed thoroughly before ignition into a fuel-lean mixture. Combustion occurs under well-controlled conditions with excess air while maintaining temperature low. This approach minimizes formation of thermal NOx by controlling temperature and oxygen carefully. Prompt NOx formation is minimized by maintaining conditions with excess oxygen.

Another approach to limiting NOx formation is oxygen combustion. Oxygen combustion reduces thermal NOx formation by mostly eliminating the nitrogen in the combustion air that is the source of thermal NOx. Oxygen combustion is not as widely used as the above methods due to the cost of producing oxygen, except in specific applications that will be discussed later. In each of the following chapters, we will explore the specific combustion control technologies that utilize these principles for controlling NOx formation.

1.2.2 Reducing NOx that is formed

When NOx must be controlled to levels lower than those possible through combustion controls, post-combustion controls are necessary. Post-combustion controls are generally divided into the following approaches:

- *Selective reduction* utilizes a nitrogen-containing reducing agent, usually ammonia or urea, to react selectively with NOx under oxygen rich conditions to reduce the NOx to molecular nitrogen. Selective reduction is further divided into catalytic or non-catalytic reduction, depending upon whether or not a catalyst is used.

- *Non-selective reduction* reduces the NOx under conditions where little or no oxygen is available. Non-selective reduction is further divided into catalytic or non-catalytic reduction, depending upon whether or not a catalyst is used.

- *Scrubbing* of NOx is possible if NOx is first oxidized to a water-soluble form and then captured in a wet scrubber.

Selective reduction is the most commonly used form of post-combustion NOx control for the types of sources described in this document. This is because all of the combustion applications described here usually entail operation with excess air, rendering non-selective reduction less applicable. It is also because these applications usually do not have wet scrubbers, which would be necessary for scrubbing of NOx. As a result, selective reduction methods tend to be more appropriate technically and more cost effective in most cases.

2. Industrial Boilers and Electrical Generating Unit Boilers

2.1 Introduction and Summary of this Section

The purpose of this section is to provide a description of the source category, the mechanism of NOx formation, the technical feasibility of controls, the cost effectiveness of controls, the existing and proposed regulations and the sources affected by the regulations.

Most Industrial, Commercial, and Institutional (ICI) boilers burn clean fuels, such as natural gas and distillate fuel oil, which are low in fuel nitrogen. Baseline emissions from such boilers are inherently low. These boilers can be controlled to the target levels by a number of combustion modification techniques including low NOx burners (LNB) and flue gas recirculation (FGR). These techniques are often less expensive than post combustion techniques such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR). However, a combination of combustion and post-combustion controls can sometimes be the most effective approach.

Some ICI boilers burn either residual fuel oil or coal which contain significant levels of fuel nitrogen. To economically control NOx emissions from such boilers, it may be necessary to use fuel that is low in nitrogen content and choose combustion conditions that generate a lower amount of NOx during combustion. Stoker and fluidized bed combustion (FBC) boilers operate at low combustion temperature and generate low levels of NOx emissions. Controlling NOx emissions from such boilers can be achieved by the use of combustion controls possibly in combination with SNCR technology. Pulverized coal (PC) fired boilers operate at higher temperatures and generate higher levels of NOx emissions compared to stoker and FBC boilers. Controlling NOx emissions from such boilers may involve the use of post-combustion technologies in combination with combustion controls. NOx emissions from residual fuel oil-fired boilers can be controlled level by using residual fuel oil which is lower in fuel nitrogen, switching to distillate fuel oil, or by a combination of combustion and post combustion technologies.

Wood-fired boilers are inherently low NOx emitters. These boilers can be controlled by SNCR technology. Currently, there are no wood-fired boilers located at any facility that is a major source for NOx emissions.

Small electrical generating unit (EGU) boilers (less than or equal to 25 megawatts (MW) capacity) are similar to ICI boilers and NOx emissions can be controlled by the use of combustion controls possibly in combination with SNCR technology. Most large EGU boilers in Illinois burn coal and, to a much lesser extent, natural gas or residual fuel oil. Most of these facilities are already equipped with some NOx controls that may include NOx burners and/or post-combustion controls.

The regulations target those boilers in the Chicago and Metro-East non-attainment areas (Chicago NAA and Metro-East NAA) that are located at a major source of NOx emissions. A major source is a source that emits or has the potential to emit 100 tons or more of NOx per year. Boilers regulated under the NOx SIP Call are not exempt from the rule. However, EGU boilers that are subject to the Multi-Pollutant Standard (MPS) or Combined Pollutant Standards

(CPS) included in Illinois' Clean Air Interstate Rule (CAIR) and Mercury Rule are exempt from this proposed rulemaking. ICI boilers that are greater than100 million Btu/hour are subject to the numerical emission limits of Table 2-1a. Annual combustion tuning is required for boilers equal to or less than 100 MMBtu/hr that emit 15 tons per year or more of NOx and 5 tons or more of NOx during the ozone season. Combustion tuning is expected to reduce NOx emissions from 5 to 25 percent. Table 2-1a summarizes the requirements of the proposed rule for ICI boilers, small EGU boilers, and auxiliary boilers. It should be noted that all ICI boilers, small EGU boilers, and auxiliary boilers are referred to as industrial boilers for the purpose of the proposed rule. Table 2-1b summarizes the requirements of the proposed rule for large EGU boilers.

Table 2-1a. Emissions Requirements of Proposed Industrial and Small EGU Boilers RACT Rule

Fuel	Boiler type	Heat Input (MMBtu/hr)	Emissions limit (lb/MMBtu)
Gas	Industrial	> 100	0.08
Other Fuel Oil	Industrial	> 100	0.15
Distillate Oil	Industrial	> 100	0.10
Solid Fuel	Except CFBC	>250	0.18
Solid Fuel	Except CFBC	>100 & ≤250	0.25
Solid Fuel	Industrial CFBC	>100	0.10
All	Industrial*	≤100	CT
All	Auxiliary**	≤250	CT

* Applies to all boilers ≤100 mmBtu/hour if annual NOx ≥15 tpy and ozone season NOx ≥5 tons
**Auxiliary boiler ≤250 mmBtu/hour and a capacity factor ≤20% subject to combustion tuning requirement.

Table 2-1b. Emissions Requirements of Proposed large EGU Boiler RACT Rule

Fuel	Began operation	Size	Emissions limit (lb/MMBtu)
Gas	Pre-2008	>25 MW	0.06
Gas	2008 or later	>25 MW	0.06
Oil	Pre-2008	>25 MW	0.10
Oil	2008 or later	>25 MW	0.08
Solid Fuel	Pre-2008	>25 MW	0.09
Solid Fuel	2008 or later	>25 MW	0.09

Facilities subject to MPS or CPS are exempt from these requirements

2.2 Process Description and Sources of Emissions

2.2.1 Process Description

Boilers use heat to either convert water into steam or produce hot water for a variety of applications. There are two varieties of boilers for these processes: electrical generating unit (EGU) and industrial/commercial/institutional (ICI). EGUs differ from ICIs mainly in size, steam application, and design. In this section, the main focus is on small to large ICI boiler types. Larger ICI boilers can be comparable to EGU systems.

Heat is provided by the combustion of fuel which may be gaseous, liquid, or solid. The overall functioning of steam-generating equipment is governed by the thermodynamic properties of the working fluid. By the simple addition of heat to water in a closed vessel, a vapor is formed which has greater specific volume than the liquid. If the generated steam is discharged at a controlled rate, commensurate with the rate of heat addition, the pressure in the vessel can be maintained at any desired value, and thus be held within the limits of safety of the construction.

Technical and economic factors indicate that the most effective way to produce high pressure steam is to heat water continuously in small diameter tubes. Two distinct boiling systems are used to accomplish this task: those that include a steam drum and those that use once through steam generators. A steam drum system is easier to control than a once through steam generator system. In both systems, water must continuously pass through, or circulate through, the tubes for the system to generate steam continuously.

Two different approaches to circulation of water are commonly used: natural or thermal circulation, and forced or pumped circulation. In natural circulation, the rate of flow or circulation of water depends upon the difference in average density between the unheated water and the heated steam-water mixture. In forced or pumped circulation, a mechanical pump is added to the simple flow loop and the pressure difference created by the pump controls the water flow rate.

Heat transfer from hot combustion gases to water varies with the boiler type. In a watertube boiler, combustion heat is transferred to water through the tubes which line the furnace walls and boiler passes. In a firetube boiler, the hot combustion gases flow through tubes immersed in the water. Figure 2-1 shows a water tube boiler and a firetube boiler. In a cast iron boiler, combustion gases rise through a vertical heat exchanger and out through an exhaust duct. Water in the heat exchanger tubes is heated as it moves upward through the tubes.

Watertube boilers can produce steam rapidly and can adapt to rapid changes in demand. Generally, watertube boilers are more complex than firetube boilers and therefore are more expensive to install and operate. However, firetube boilers respond less quickly to load variations and are used where load is generally constant. Quick pressure changes can be catastrophic for firetube boilers.[1] Cast iron boilers are used to produce low pressure steam or hot water for domestic and small commercial operations.

Since most watertube boilers can produce steam rapidly, they are preferred for industrial applications. Most ICI watertube boilers have heat input capacities ranging from 10 to 250 million Btu/hour, although some are as large as 1500 million Btu/hour. Older watertube boilers greater than 200 million Btu/hr tend to be field erected and have multiple burners. Newer watertube boilers tend to be single burner and packaged. Large watertube boilers often use combustion air preheat. Small EGU boilers are similar to industrial boilers in design, and generate 25 or less megawatts of electricity per hour.

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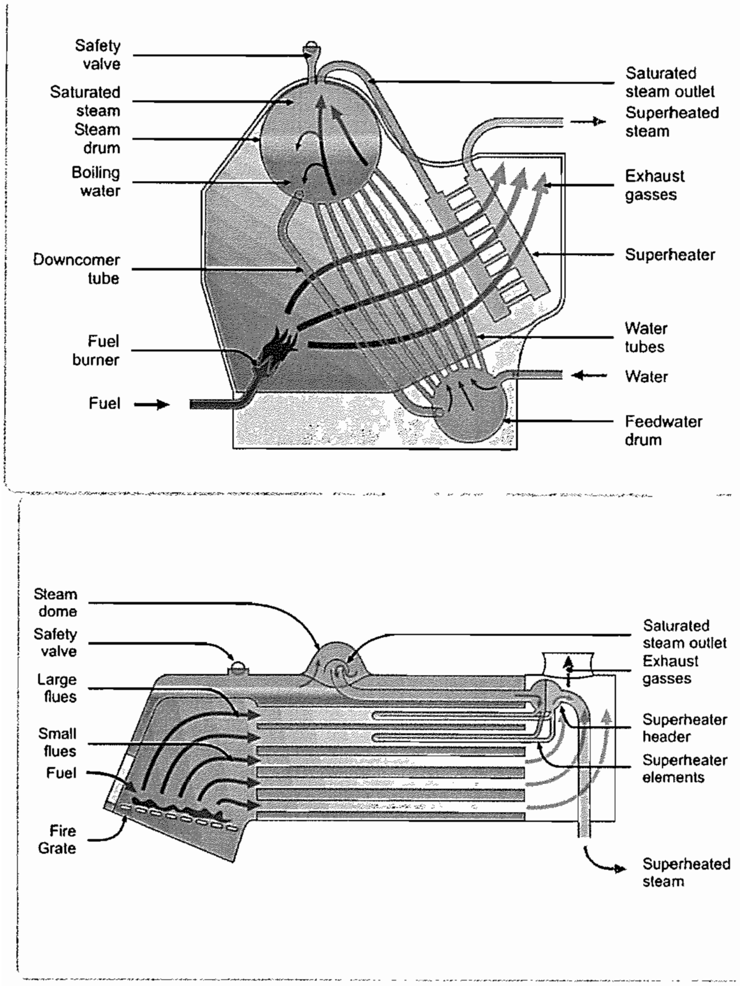
[1] Energy & Environmental Analysis, Inc. (2005). "Characterization of the U.S. Boiler Industrial Commercial Boiler Population." Submitted to Oak Ridge National Laboratory.

Figure 2-1. Water-tube boiler (upper) and fire-tube boiler (lower)
(http://commons.wikimedia.org/wiki/Image:Water_tube_boiler_schematic.png and
http://en.wikipedia.org/wiki/Image:Locomotive_fire_tube_boiler_schematic.png, 2007)



Since firetube boilers respond less quickly to load variations, their heat input capacities are limited to less than 50 mmBtu/hr and steam pressures are limited to 300 pounds per square inch gauge. Firetube boilers are generally prefabricated in the shop, shipped by rail or truck and are thus referred to as packaged. Combustion air preheat is never used in firetube boilers. They are primarily used in commercial and institutional sectors and used to be common for locomotives (a locomotive fire-tube boiler is pictured). Commercial boilers typically have input capacities below 15 mmBtu/hr.

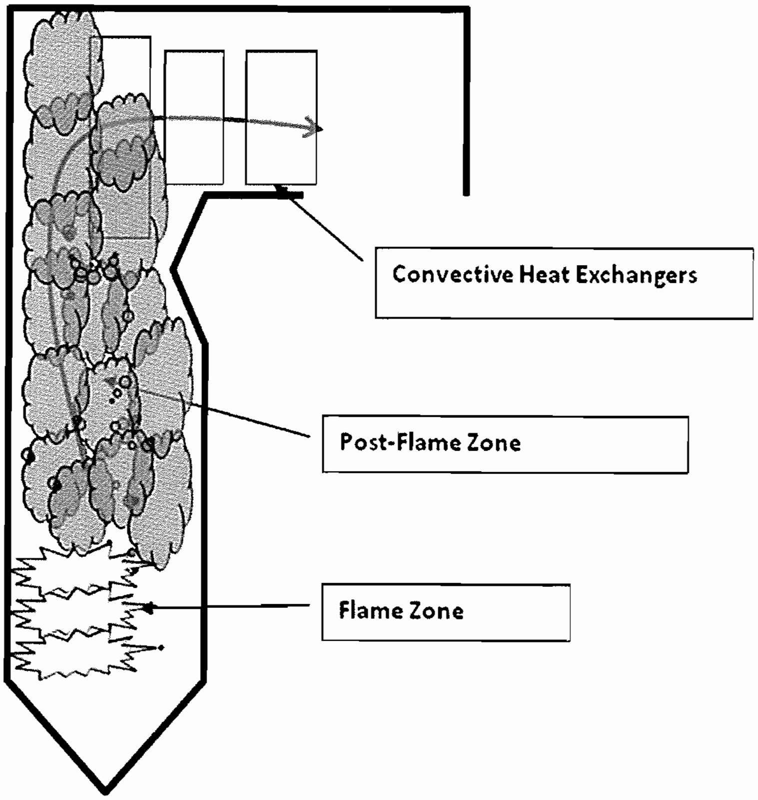
Since cast iron boilers produce low pressure steam or hot water, they are preferred for domestic and small commercial operations. All cast iron boilers are prefabricated in the shop before shipping. Cast iron boilers are used primarily in the residential and commercial sectors, and have heat input capacities up to10 mmBtu/hr.

2.2.2 Furnace Firing Configurations and Factors Affecting Baseline NOx Emissions

There are several factors which affect baseline NOx emissions. These include boiler design, fuel type, and boiler operation. Since these factors influence each other, baseline emissions vary a lot from boiler to boiler. This section discusses how boiler design, fuel characteristics, and boiler operating characteristics can influence baseline (uncontrolled) NOx emissions.

There are several boiler designs available in the market depending on the type of fuel burned. For combustion of coal, boilers may be tangentially-fired, wall-fired, cyclone-fired, stoker-fired or fluidized bed-fired. Each type of furnace has specific design characteristics that can influence NOx emissions levels. For natural gas and fuel oil, ICI boilers may be tangential-fired or wall-fired. Other designs are available, but are not used as much in the ICI boiler industry.

Figure 2-2 Typical configuration for a large industrial or EGU boiler.



In all boilers, the flames and the hot exhaust gases produced by the flames heat the water through radiant heat transfer and convective heat transfer, as shown in Figure 2-2. Figure 2-2 is typical of a large industrial boiler or EGU.

Factors which influence baseline NOx emissions include heat release rate, combustion temperature, oxygen levels and air-fuel mixing. Pre-NSPS boilers were not designed to minimize NOx emissions. Boilers subject to the subparts D or Da of NSPS have some type of NOx control. A brief discussion of boiler designs for various types of fuels is provided below.

2.2.2.1 Coal-Fired Boilers

Tangentially-Fired: Tangentially-fired burners are incorporated into stacked assemblies that include several layers of primary fuel nozzles interspersed with secondary air supply nozzles. The stacked assemblies are located in the corners of the boiler and are directed somewhat off-center to produce a rotating fireball in the center of the furnace. Tangentially-fired boilers tend to produce somewhat lower uncontrolled NOx emissions than wall or cyclone-fired boilers.

Tangential-firing is quite common in electric utility boilers, but not so common in ICI boilers. None of the ICI boilers in the Illinois inventory are tangentially fired. However, several of the large EGU boilers are tangentially fired.

Wall-Fired: ICI boilers firing pulverized coal are more likely to be wall fired than tangentially fired. Unlike tangentially-fired units, wall-fired units tend to operate at slightly higher temperatures and hence generate slightly higher levels of NOx. Only single and opposed wall-fired units are discussed here as they are often used for ICI boilers. Wall firing is also common for EGU boilers.

Figure 2-3 – Circular burner installed on wall-fired boiler[2]

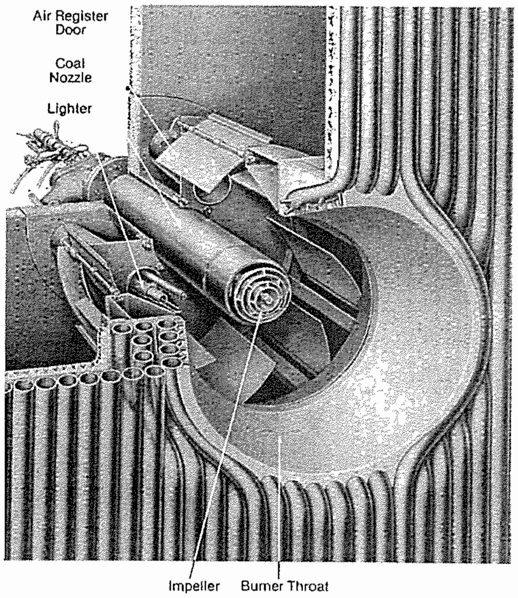
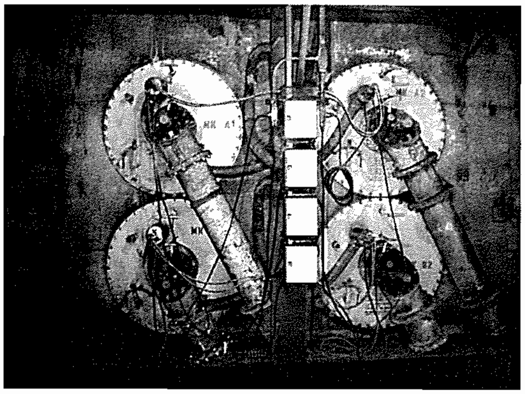


Fig. 6 Circular register pulverized coal burner with water-cooled throat.

In the single and opposed wall-fired units, several rows of circular burners – similar to what is shown in Figures 2-3 and 2-4 - are mounted on the front or rear wall of the furnace. Opposed-wall units also use circular burners, but have burners on two opposing furnace walls. Circular burners introduce a fuel-rich mixture of fuel and primary air into the furnace through a central nozzle. Secondary air is supplied to the burner through separate adjustable air vanes. The high level of turbulence between the fuel and secondary air streams create a near stoichiometric combustion mixture. Under these conditions, combustion gas temperatures are high and contribute to thermal NOx formation. High turbulence also causes the time available for fuel reactions under reducing conditions to be relatively short, thus increasing the potential for formation of fuel NOx. Wall-fired boilers burn pulverized coal which is of the consistency of talcum powder.

Baseline NOx emissions for uncontrolled dry-bottom wall-fired boilers using pulverized coal vary, but are typically in the range of about 0.45 to 0.90 lb/MMBtu – depending upon fuel and firing condition.

Figure 2-4. Arrangement of four wall-fired burners



Cyclone-Fired: Cyclones are wet-bottom furnaces, in which fuel (typically crushed coal) and air are introduced into a small highly turbulent combustion chamber. In this high-temperature combustion chamber most of the ash becomes molten and is drained from the bottom of the furnace. There are no cyclone coal-fired ICI boilers in theIllinois inventory. However, there are several cyclone-fired units in the large EGU inventory.

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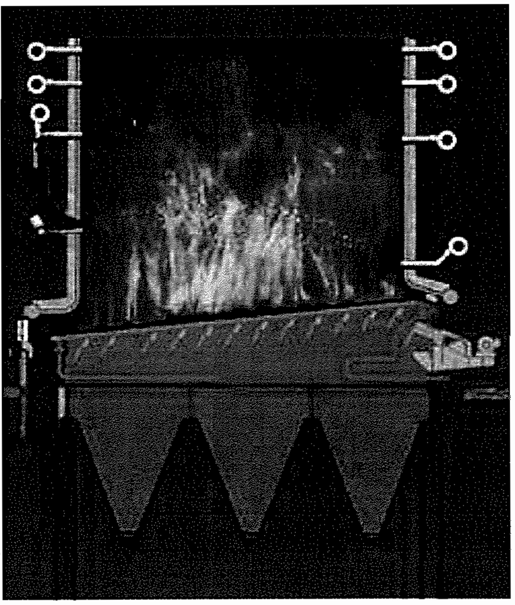
[2] Babcock & Wilcox Company, Steam, It's Generation and Use, 40th Edition, 1992

Figure 2-5. Stoker-fired boiler (www.detroitstoker.com)



Stoker-Fired: In stokers, crushed coal or other solid fuel is burned on a grate with some of the combustion air passing up through the grate, as shown on Figure 2-5. Stokers are the oldest method for distributing fuel and air for combustion. Stokers typically have low gas velocities through the boiler in order to prevent flyash erosion and are operated with high levels of excess air to insure complete combustion and maintain relatively low grate temperature. Low NOx emissions are mainly due to lower furnace temperatures compared to other boiler types. However, finer coal sizes produce greater NOx emissions. A study conducted at a Utah University laboratory showed that finer coal sizes less than 1/10th of an inch generated higher NOx levels.[3]

Stoker-firing systems account for approximately 90 percent of coal-fired waterube ICI boilers nationwide. However, historic trends pertaining to the marketability of these firing systems has shown a steady decline. Thus, most stoker-firing systems today are greater than 40 years old. Because stoker boilers can have long lives, retrofit controls/modifications are mostly appropriate to meet performance and environmental objectives.

Stoker-fired systems can be divided into three groups: underfeed stokers, overfeed stokers, and spreader stokers. Underfeed stokers were once fairly common, but because of high maintenance costs and slow response to varying loads, these are less competitive in the present market. Maximum heat input capacity of underfeed stokers is limited to 500 mmBtu/hr. Spreader stokers use continuous ash discharge traveling grates, intermittent-cleaning dump grates, or reciprocating continuous cleaning grates. They are most popular in industry today because of their good response to varying load conditions and capability to burn various grades of coal. However, among the stokers, spreader stokers generate the highest levels of NOx emissions because a portion of the coal fines burn in suspension in the spreader design. Heat input capacity of spreader stoker ranges from 5 to 550 mmBtu/hr. Overfeed stokers are chain, traveling, and water-cooled vibrating grate types that range up to 350 mmBtu/hr heat input capacity.

Baseline NOx emissions for stoker coal-fired boilers vary from 0.19 to 0.77 lb/mmBtu with average NOx levels of 0.29 to 0.53 lb/mmBtu, depending on the type of stoker firing.

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[3] Johnson, Neil. (2002). "Fundaments of Stoker Fired Boiler Design and Operation." Presented at the CIBO Emission Control Technology Conference

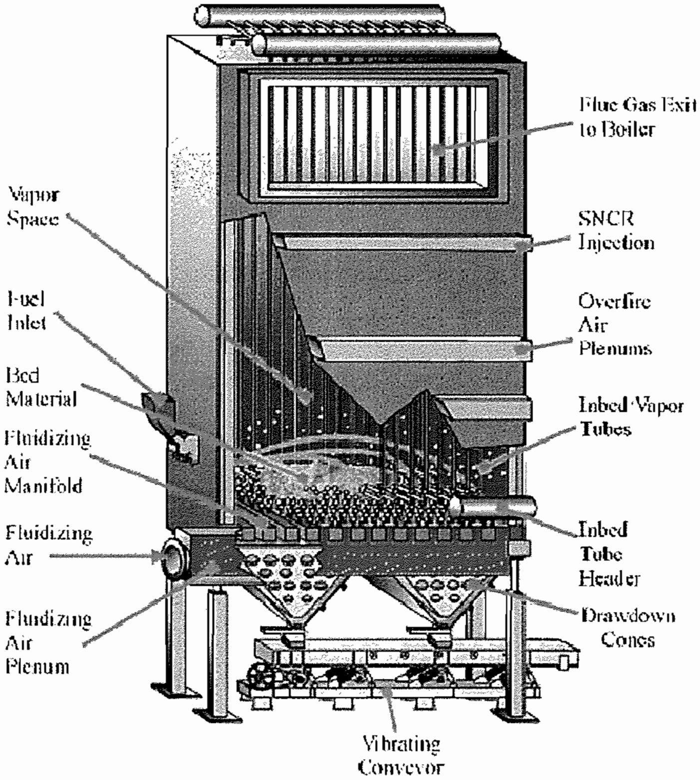


Figure 2-6. Fluidized Bed Combustor
(www.energyproducts.com)

Fluidized bed combustion (FBC) boilers: FBC boilers can handle a wide variety of solid fuels and are capable of low NOx and SO_2 emissions. There are two major categories of FBC systems: (1) atmospheric, operating at a slightly negative draft, and (2) pressurized, operating at from 4 to 30 atmospheres. No pressurized FBC units are currently used in the ICI sector. Atmospheric FBC boilers (pictured in Figure 2.6) are further subdivided into two categories, namely bubbling bed and circulating bed. The fundamental distinguishing feature between the two is the fluidizing velocity. Circulating FBC boilers operate at high fluidizing velocities, can achieve higher combustion efficiency and better sorbent utilization as compared to bubbling bed and hence they are preferred over bubbling bed for large boilers.

The coal burning industrial FBC boilers range from 1.4 to 1075 mmBtu/hr heat input capacity. Baseline NOx emissions for bubbling FBC coal-fired boilers vary from 0.11 to 0.81 lb/mmBtu with average NOx levels of 0.32 lb/mmBtu, and for circulating FBC coal-fired boilers NOx emissions vary from 0.14 to 0.60 lb/mmBtu with average NOx levels of 0.31 lb/mmBtu.

The coal burning FBC boilers in the electrical generating industry may be as large as 200 megawatts or more. NOx emissions from CFBC boilers are in the range of 0.1 to 0.3 lb/mmBtu with typical levels of 0.2 lb/mmBtu.

2.2.2.2 Natural Gas-Fired Boilers

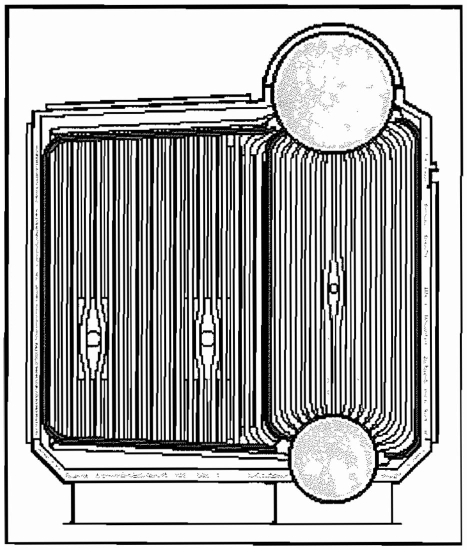
Natural gas-fired boilers are similar in design to oil-fired boilers. Some boilers have dual fuel capability. Boilers that are strictly gas-fired have the smallest furnace volume of all ICI boilers because of rapid combustion, low flame luminosity, and ash free content of natural gas. Because fuel nitrogen content of natural gas is very low, its combustion mainly produces thermal NOx.

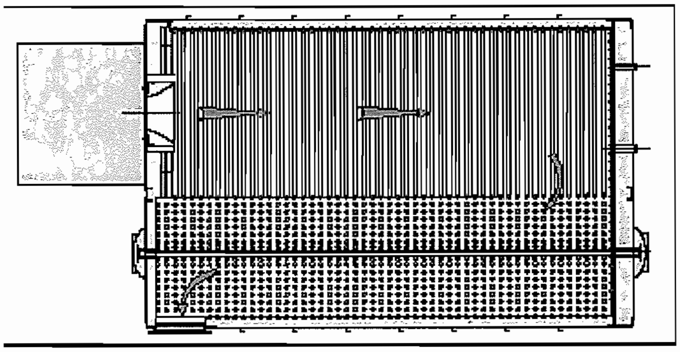
Natural gas-fired boilers may be either tangentially-fired or wall-fired. Boilers larger than150 mmBtu/hr are usually field-erected and have multiple burners. Boilers smaller than 100 mmBtu/hr capacity are usually packaged and have a single wall-fired burner such as in the D-type package boiler shown in Figures 2-7a and 2-7b. In older boilers, multiple-burner arrangements provide a means of controlling heat input in lieu of turndown capability. For newer units, single burners are used even for units as large as 250 mmBtu/hr.

Figure 2-7a.
D-Type Boiler vertical cross section

Figure 2-7b.[4]
D-Type Boiler horizontal cross section

Shop assembled units from 10,000 pph to 250,000 pph steam, fired with gas or liquid fuels
www.neboiler.com





NOx emissions from natural gas-fired boilers, on the whole, range from 0.06 to 0.31 lb/mmBtu for units that are smaller than 100 mmBtu/hour, and range from 0.11 to 0.45 lb/mmBtu for units that are larger than 100 mmBtu/hr capacity as per ACT for ICI boilers. ACT does not provide baseline NOx emissions information based on firing type. Boilers subject to NSPS, Subparts Da and Db are limited to NOx emissions of 0.20 lb/mmBtu and boilers subject to Subpart Dc are limited 0.10 lb/mmBtu if the heat release rate is low and 0.20 lb/mmBtu if the heat release rate is high. Therefore, baseline NOx emissions from boilers subject to NSPS are likely to be lower.

Data from Cleaver-Brooks, a manufacturer of natural gas-fired steam boilers, show that low NOx levels can be maintained through proper planning of boiler configuration. Adequate planning involves several steps, all of which promote the goal of reducing NOx levels below permit levels. As each table demonstrates, the levels of NOx are lower than the standard limits. Table 2-2 illustrates the NOx emissions (in ppm and lb/MMBtu) for different natural gas-fired boiler capacities and manufacturing processes.

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[4] Nebraska boiler web site: www.neboiler.com

Table 2-2.: Data from Cleaver-Brooks Study

	Date Tested	Fuel Type	NOx (ppm @3% O_2)	NOx (lb/MMBtu)	Flowrate (dscfm)	Type/Size
< 9 ppm NOx requirements (natural gas)						
San Joaquin General	5/18/05	NG	7.4	.009	1941	20. 9 MMBTH Cleaver Brooks CEW (retrofit)
		NG	6.9	.0084	2213	
		NG	8	.0097	1717	
Kraft General Foods	5/23/05	NG	4.4	.0053	767	33.8 MMBTH Cleaver Brooks NTD336 retrofit
		NG	4.8	.0059	749	
		NG	5	.0061	753	
SK Foods	10/20/03	NG	5.4	.0065	7737	89.1 MMBTH Natcom
		NG	5.3	.0065	7618	
		NG	5.5	.0067	7679	
< 12 ppm NOx requirements (natural gas)						
See's Candies	12/17/02	NG	11.1	0.0142	376	7 MMBTH Cleaver Brooks FLX
		NG	10.3	0.0132	627	
		NG	9.9	0.0127	1146	
Boeing LB, CA	3/25/04	NG	9.2	0.0118	1834	16.3 MMBTH Cleaver Brooks
		NG	9.8	0.0125	1850	
Baxter Health Care	10/10/02	NG	8.9	0.014	1254	20.9 MMBTH Cleaver Brooks CEW
		NG	9.8	0.0125	2464	
		NG	8.9	0.014	4873	
< 15 ppm NOx requirements (natural gas)						
E & J Gallo Winery	5/19/05	NG	10.6	0.0129	1436	10.2 MMBTH Cleaver Brooks
		NG	9.7	0.0118	1221	
		NG	8.5	0.0104	379	
Memorial Hospital North	1/17/06	NG	11.7	0.0142	2804	14.6 MMBTH Cleaver Brooks Unit #2
		NG	11.9	0.0144	2443	
		NG	11.9	0.0149	2421	
Georgia Pacific Corp	5/31/05	NG	10.7	0.013	2203	16.3 MMBTH Cleaver Brooks
		NG	10.6	0.0129	2473	
		NG	11.5	0.014	1811	
< 20 ppm NOx requirements (natural gas)						
Carpenter Company	5/20/05	NG	27	0.0328	735	6.3 MMBTH Cleaver Brooks
		NG	27.2	0.0331	634	
		NG	27.7	0.0337	502	
Paramount Petroleum	12/21/05	NG	23.2	0.0282	1934	13 MMBTH Broach Boiler Unit #1
		NG	23.1	0.028	1874	
		NG	22.5	0.0273	1871	
Bunge Foods	2/15/06	NG	20.1	0.33	1495	25.1 MMBTH Cleaver Brooks
		NG	19.7	0.0325	1341	
		NG	19.9	0.0313	1175	

*notes: (ppm = parts per million)
(dscfm = dry standard cubic feet per minute)
(source :.Willems, Daniel (2006). "Cleaver Brooks: Letter to Mr. Regulator " May 19, 2006)

2.2.2.3 Oil-Fired Boilers

Oil-fired boilers do not require as large a furnace volume as coal-fired boilers for complete combustion. Similarly, because the combustion gases contain less entrained ash, the convective pass of oil-fired boilers can be more compact than coal-fired boilers, but tend to be somewhat larger than gas-fired boilers. In addition, oil-fired boilers operate at lower excess air levels than coal-fired boilers. The more compact design of oil-burning furnaces has an impact on NOx emissions from oil-fired units. Even though the nitrogen content of oil is generally lower than that of coal, higher flame temperatures result in increased formation of thermal NOx. This thermal NOx contribution can more than offset the lower fuel NOx contribution from the oil.

Oil-fired boilers may be subdivided into tangential, vertical, and wall-fired units. Boilers larger than 150 mmBtu/hr capacity are usually field-erected and have multiple burners. Boilers smaller than 100 mmBtu/hr capacity are usually packaged and have single burners. In older boilers, multiple-burner arrangements provide a means of controlling heat input in lieu of turndown capability. For newer units, single burners are used even for units as large as 200 mmBtu/hr.

Among oil-fired boilers, tangentially-fired boilers generate lower NOx emissions compared to other types of boilers because of lower peak flame temperatures. For distillate oil-fired watertube boilers NOx emissions range from 0.08 to 0.16 lb/mmBtu for units that are smaller than 100 mmBtu/hour, and range from 0.18 to 0.23 lb/mmBtu for units that are larger than100 mmBtu/hour capacity as per ACT for ICI boilers. For residual oil-fired watertube boilers NOx emissions range from 0.20 to 0.79 lb/mmBtu for units that are smaller than 100 mmBtu/hour, and range from 0.31 to 0.60 lb/mmBtu for units that are larger than100 mmBtu/hour capacity as per ACT for ICI boilers. ACT for ICI boilers does not provide baseline NOx emissions information based on firing type. NSPS, Subpart Da and Db limit NOx emissions to 0.80 and 0.30 lb/mmBtu, respectively, and boilers subject to Subpart Dc are limited to 0.30 lb/mmBtu if the heat release rate is low and 0.40 lb/mmBtu if the heat release rate is high. Therefore baseline NOx emissions from boilers subject to NSPS are likely to be lower.

Cleaver Brooks data demonstrates that proper retrofit/installation can substantially reduce the level of NOx emissions. Levels of NOx in lb/MMBtu are well below the NSPS limits. With small capacity, 6 MMBtu/hr, NOx emissions are between 0.0341 – 0.0364 lb/MMBtu, while larger boiler capacity, 20.9 MMBtu/hr, shows levels between 0.0307 – 0.0387 lb/MMBtu. Table 2-3 illustrates the low NOx levels emitted from the boilers while using ultra low NOx burners.

Table 2-3. Data from Cleaver-Brooks Study

	Date Tested	Fuel Type	NOx (ppm @3% O_2)	NOx (lb/MMBtu)	Flowrate (dscfm)	Type/Size
< 40 ppm NOx requirements (Amber Oil)						
Patton State Hospital – boiler #3	12/20/02	Amber	30.2	0.0387	2583	20.9 MMBTH Cleaver Brooks
		Amber	29.8	0.0382	3156	
		Amber	24	0.0307	4475	
See's Candies	12/17/02	Amber	28.4	0.0364	1053	6 MMBTH Cleaver Brooks M4
		Amber	26.6	0.0341	2184	
		Amber	28.1	0.0360	3361	

Willems, Daniel (2006). "Cleaver Brooks." Letter to Mr. Regulator

2.2.3 Fuel Characteristics

Natural gas and distillate fuel are low in nitrogen and hence NOx produced is mainly thermal NOx. As the nitrogen content of the fuel increases, significant contribution from fuel nitrogen to total NOx occurs. Thus, the nitrogen content of the fuel (see Table 2-4) is a partial indicator of NOx emission potential.

Obviously, design characteristics may dictate the type of fuel used in a given boiler. Natural gas is a vapor, oil is a liquid, and coal is a solid. Depending upon whether the fuel is a gas, liquid, or solid, injection method also varies. In addition, furnace volume varies with the type of fuel burned. For coal-fired boilers, furnace volume is larger than for gas and oil-fired boilers. As a result, less thermal NOx is formed during oil or gas combustion in multi-fuel boilers and these boilers are more amenable to NOx controls due to larger furnace volumes.

Table 2-4: Typical Fuel Nitrogen Contents of Fossil Fuels

Fuel	Nitrogen (wt%)
Natural gas	0-0.2
Distillate Fuel Oil	0-0.4
Residue Oil	0.3-2.2
Subbituminous coal	0.8-1.4
Bituminous coal	1.1-1.7

2.2.4 Boiler Operating Conditions

As a boiler goes through its daily operating cycle, several factors including operating load, excess oxygen, burner secondary register settings, and mill operations also change, and that may affect NOx emissions.

Although boiler load influences NOx emissions, it is obviously not a practical method to control NOx emissions. The effect of excess air and burner secondary air settings on NOx emissions can vary. Change of excess air changes flame stoichiometry and increasing secondary air flow may bring cooler secondary air into the furnace, lower flame temperature, and increase air fuel mixing. The net result is that both actions may either raise or lower NOx emissions.

About 90% of ICI boilers (in number) burn gaseous or liquid fuels in Illinois and the remaining 10% burn coal or some other solid fuel. However, coal contributes a larger share to the total emissions because it tends to be used on larger boilers and because the emissions rates for coal tend to be higher. Coal has not been utilized on smaller ICI boilers as extensively as oil or natural gas, chiefly due to cost considerations. Most coal-fired boilers are stoker fired. Natural gas and fuel oil are burned in single or multiple burner arrangements, such as the D-Type boiler of Figure 2.7. Many ICI boilers have dual fuel capability. In smaller units, the natural gas is normally fed through a ring with holes or nozzles that inject fuel into the air stream. Fuel oil is atomized with steam or compressed air and fed into burner. Heavy fuel oils must be preheated before injection to decrease viscosity and improve atomization.

Stoker-firing systems account for approximately 90 percent of coal-fired watertube ICI boilers nationwide. Coal in crushed form is burned mostly on a grate (moving or vibrating) in stoker-fired boilers. Stoker systems can be divided into three groups: underfeed stokers, overfeed stokers and spreader stokers. These systems differ in how fuel is supplied to either a moving or a vibrating grate for burning. The most popular methods are the spreader and overfeed. All stokers use underfeed air to combust char on grate, combined with one or more levels of overfire air introduced above the grate. This helps ensure complete combustion of volatiles and low combustion emissions.

Pulverized coal is typically burned only in boilers larger than 100 mmBtu/hr. Below this level, the required coal-handling and pulverizing equipment make pulverized coal uneconomical. Pulverized coal-burn coal is broken up in a mill to a consistency of talcum powder (i.e., at least 70% of the particles will pass through a 200-mesh sieve). PC-fired boilers account for a small percentage of the ICI watertube boiler population. However, they tend to be the largest ICI boilers and therefore the highest emitters.

In fluidized bed combustion (FBC) boilers, crushed coal is burned either in a stationary bubbling bed or in a circulating fluidized bed. The bed material is often a mixture of sand and limestone for capturing SO_2. They operate at much lower temperatures compared to PC boilers. FBC boilers have become particularly popular because they emit low NOx and SO2 emissions and can burn low grade coals.

Many small boilers operate with little supervision and are fully automated. Industrial boilers may be located either inside the buildings or outside the buildings. Most commercial and institutional boilers are fully enclosed inside buildings. The location of these boilers often influences the feasibility of retrofit for some control technologies because of poor access and limited available space.

2.2.5 Baseline NOx Emissions

Baseline NOx emissions are strongly influenced by boiler design, type of fuel burned, peak flame temperature, and oxygen concentration. Coal-fired generally emit higher NOx emissions than oil-and natural gas-fired boilers because of higher fuel nitrogen contents. Natural gas-fired boilers emit the lowest NOx emissions because natural gas has very low fuel nitrogen contents. Among coal-fire boilers, cyclone-fired boilers emit highest NOx emissions because of higher flame temperature. Among stoker coal-fired boilers, spreader stoker boilers emit the highest NOx emissions because a portion of coal fines burn in suspension in the spreader design. Fluidized bed boilers emit significantly lower NOx emissions compared to PC- fired units because they operate at much lower temperatures. The large variations in baseline NOx emissions from FBC boilers are due to variations in air distribution amongst FBC units. Newer FBC boilers incorporate a staged air addition that suppresses NOx levels.

Among oil-fired boilers, distillate oil-fired boilers emit the least amount of NOx emissions because of lower fuel nitrogen contents. The nitrogen content of residual fuel oils varies from 0.3 to 2.2 percent. This large variation in fuel nitrogen content results in large variations in baseline NOx emissions from combustion of residual fuel oils.

Generally, larger boilers tend to have higher baseline NOx emissions because of the higher heat release rate that generally accompanies the larger units in order to minimize the size of the furnace. Another important factor is the use of preheated combustion air with the larger boilers. The use of preheated air raises the flame temperature and hence contributes to higher NOx emissions.

Newer boilers subject to NSPS have some kind of NOx control, and hence baseline NOx emissions from newer boilers are lower. However, data compiled by the ACT document for ICI boilers does not provide baseline NOx emissions from newer boilers separately.

Table 2-5 below provides baseline NOx emissions from various ICI boilers.

Table 2-5: Summary of Baseline (Uncontrolled) NOx Emissions for ICI Boilers (ACT document)

Fuel	Type of Unit	Boiler Size mmBtu/hr	Uncontrolled NOx range, lb/mmBtu	Average NOx lb/mmBtu
Natural Gas	Watertube Boiler	>100	0.11-0.45	0.26
Natural Gas	Watertube Boiler	<100	0.06-0.31	0.14
Distillate Oil	Watertube Boiler	>100	0.18-0.23	0.21
Distillate Oil	Watertube Boiler	<100	0.08-0.16	0.13
Residual Oil	Watertube Boiler	>100	0.31-0.60	0.38
Residual Oil	Watertube Boiler	<100	0.20-0.79	0.36
Coal	Pulverized Dry Bottom Wall-fired Boiler	>100	0.46-0.89	0.69
Coal	Spreader stoker Boiler	>50	0.35-0.77	0.53
Coal	Underfeed stoker Boiler	>50	0.31-0.48	0.39
Coal	Overfeed stoker Boiler	>50	0.19-0.44	0.29
Coal	Bubbling FBC Boiler	>50	0.11-0.81	0.32
Coal	Circulating FBC Boiler	>50	0.14-0.60	0.31
Wood**	Not Specified	>70	0.17-0.30	0.24
Wood**	Not Specified	<70	0.01-0.05	0.022

* There are no cyclone coal-fired ICI boilers in the Illinois inventory

** Wood-fired boilers are located at non-major sources (with PTE <100 tons/year) as per year 2002 inventory.

Reference for Baseline Emission Data: Alternative Control Techniques Document- NOx Emissions from Industrial/ Commercial/Institutional (ICI) Boilers, EPA-453/R-94-022. March 1994.

2.3 Technical Feasibility of NOx Control

The control of NOx emissions from existing ICI boilers can be accomplished either through combustion modification controls, flue gas treatment controls, or a combination of these technologies. In some cases, fuel substitution may be a cheaper alternative to combustion modification or post combustion controls.

Combustion modification controls such as low excess air, staged combustion air (SCA), low NOx burner (LNB), and flue gas recirculation (FGR) modify the conditions under which combustion occurs to reduce NOx formation. Post-combustion controls, such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR), reduce NOx emissions after it is formed. Combustion controls are less costly compared to post-combustion controls and have been widely used to control NOx emissions from ICI boilers. However, post-combustion controls such as SCR can achieve greater NOx reductions. The combination of combustion control and post-combustion controls provide even greater reductions than post-combustion alone.

Although combustion controls are usually the least expensive approach to controlling NOx, in some cases they may not be adequate or may be more expensive than post-combustion controls. In such cases, post-combustion controls may be more attractive.

2.3.1 Combustion Control Techniques

NOx is primarily formed by the thermal fixation of atmospheric nitrogen in the combustion air (thermal NOx) or by conversion of chemical bound nitrogen in the fuel (fuel NOx). Since fuel nitrogen contents of natural gas and distillate fuel oil are low, NOx emissions from these fuels can be effectively controlled by controlling thermal NOx. NOx emissions from coal and residual fuel oil can be reduced by controlling both thermal NOx as well as fuel NOx. Thermal NOx can be effectively controlled by decreasing the primary flame zone oxygen level or by decreasing residence time at higher temperature.

The primary flame zone O_2 level can be decreased by low excess air (LEA), oxygen trim (OT), and flue gas recirculation (FGR). This results in an overall decrease in the oxygen level and exposure of fuel nitrogen intermediates to oxygen and reduces high NOx pockets in the flame. The primary flame zone O_2 level can also be decreased by delayed mixing of fuel and air as is done in low NOx burners (LNB). Delayed mixing of fuel and air also results in a reduction of peak flame temperature. In the absence of oxygen, fuel nitrogen gets converted to N_2. A related approach is staged combustion. This approach reduces primary flame zone oxygen level by staging the amount of combustion air introduced into the burner zone, creating a primary fuel rich flame zone. Staged combustion air (SCA) can be accomplished by several means. For a multiple burner boiler, a simple approach is to take certain burners out of service (BOOS) or biasing the fuel flow to selected burners to obtain a similar staging effect. However, this may be impractical on some units due to the configuration of the fuel system. A final technique is to derate the boiler to lower the flame temperature. This approach is not attractive because it involves reducing steam generation capacity.

Low Excess Air (LEA) Firing: Low excess air (LEA) firing is the most effective boiler improvement technique one can apply without significant capital cost. As a safety factor to assure complete combustion, boilers are fired with excess air. High excess air levels may result in increased NOx formation because the excess nitrogen and oxygen in the combustion entering the flame will combine to form thermal NOx. Minimizing excess air is normally part of good combustion air management, in that it reduces the potential to carry away a lot of waste energy, and hence improves boiler thermal efficiency.

Operation of boilers with low excess air is possible in most cases, and can be applied to boilers of all sizes. Implementation may be as simple as boiler tuning using standard procedures. If boilers are operated under varying load conditions, O_2 and CO monitors can be used to provide feedback to the combustion air controller that help in refinement of the air/fuel ratio and hence reduction of heat losses to the atmosphere. Such monitors may be required. Another way to limit the amount of excess air is by designing a burner that is optimized through the use of oxygen trim controls.

One problem with low excess air is that when excess air is reduced, CO and hydrocarbon emissions may increase. In addition, at very low excess air levels, flame instability may occur and because of reducing atmosphere, accelerated corrosion of boiler tubes may result.

Generally excess air is limited to no less than 2-4% for oil and 0.5-3.0% for gas, depending on the boiler and burner design. Use of low excess air can reduce NOx emissions from 5 to 25 percent for oil-fired units, and 5 to 30 percent for coal-fired units.

Combustion tuning incorporates low excess air and inspection of the boiler for proper working conditions.

Combustion Tuning: The proposed rule requires combustion tuning for boilers less than or equal to 100 MMBtu/hr. Boilers often operate at excess air levels higher than the optimum level with the result that the combustion gases leave the boilers with a lot of waste energy. In addition, higher excess air may result in the lowering of flame temperature and reduced transfer of heat to water. Optimizing the boiler results in minimizing heat loss up the stack and improves combustion efficiency. In addition, it reduces pollution to the atmosphere.

The correct amount of excess air is determined from analyzing flue gas O_2 or CO concentrations. Inadequate excess air results in unburned combustibles (fuel, soot, smoke, and CO) while too much excess air results in heat loss due to the increased gas flow - thus lowering the overall boiler fuel-to-steam efficiency. The table below relates stack readings to boiler performance.

Table 2-6. Combustion Efficiency for Natural gas

Reference: http://www1.eere.energy.gov/industry/bestpractices/pdfs/steam4_boiler_efficiency.pdf

Excess, %		Combustion Efficiency				
		Flue gas Temperature Minus Combustion Air Temperature, oF				
Air	Oxygen	200	300	400	500	600
9.5	2.0	85.4	83.1	80.8	78.4	76
15.0	3.0	85.2	82.8	80.4	77.9	75.4
28.1	5.0	84.7	82.1	79.5	76.7	74
44.9	7.0	84.1	81.2	78.2	75.2	72.1
81.6	10.0	82.8	79.3	75.6	71.9	68.2

Assumes complete combustion with no water vapor in the combustion air

On well-designed natural gas-fired systems, an excess air level of 10% is attainable and for coal an excess air level of 15% should be achievable. An often-stated rule of thumb is that the boiler efficiency can be increased by 1% for each 15% reduction in excess air or 40°F reduction in stack gas temperature. An example of the benefits of low excess air is shown below.

> Example
>
> A boiler operates for 8,000 hours per year and consumes 500,000 million Btu (MMBtu) of natural gas while producing 45,000 lb/hour of 150-psig steam. Stack gas measurements indicate an excess air level of 44.9% with a flue gas minus combustion air temperature of 400°F. From the table, the boiler combustion efficiency is 78.2% (E_1). Tuning the boiler reduces the excess air to 9.5% with a flue gas minus combustion air temperature of 300°F. The boiler combustion efficiency increases to 83.1% (E_2). Assuming a fuel cost of $8.00/MMBtu, the annual savings are:

$$\begin{aligned}\text{Annual Savings} &= \text{Fuel Consumption x } (1 - E_1/E_2) \text{ x Fuel Cost}\\ &= 29{,}482 \text{ MMBtu/yr x } \$8.00/\text{MMBtu}\\ &= \$235{,}856\end{aligned}$$

Exhaust gas analyzers are necessary to tune a boiler. They can be portable or on-line. Portable monitors can be used periodically to monitor flue gas composition and tune boilers. There are inexpensive gas-absorbing kits available for measuring the percentage of oxygen in the flue gas. A portable monitor may cost from $500 to $1000. Computer-based analyzers display percent oxygen, stack gas temperature, and boiler efficiency. They are a recommended investment for any boiler system with annual fuel costs exceeding $50,000.
http://www1.eere.energy.gov/industry/bestpractices/pdfs/steam4_boiler_efficiency.pdf

Oxygen Trim Systems are very useful for good combustion control. When fuel composition is highly variable (such as refinery gas, or multi- fuel boilers), or where steam flows are highly variable, an online oxygen analyzer should be considered. The oxygen "trim" system provides feedback to the burner controls to automatically minimize excess combustion air and optimize the air-to- fuel ratio.

An oxygen trim system may include hardware for continuous control of reference air, and for calibration air and test gas. The full initial calibration takes only minutes to complete. Annual calibration is generally similar to periodic calibration.

An oxygen trim system can be incorporated into single point (jackshaft) positioning as well as parallel positioning boiler system controls. In a jackshaft control, the steam pressure is sensed as the basic control signal and this signal regulates the mechanical linkage attached to the fuel valve and combustion air dampers. The jackshaft control is usually set for a particular operating condition when the boiler is first installed, and adjustments are made infrequently.

In a parallel positioning control, the steam pressure is sensed as the basic control signal. This signal regulates pneumatic or electronic drivers which regulate fuel valve and combustion air dampers. In addition, some provision for operator control is also provided. The most common method today is parallel positioning.

The capital cost of an oxygen trim system for boilers ranging in size from 100 to 600 horsepower is about $10,000-11,000. The installation cost is about $6000-7000. Startup and training service costs are about $2500-4000. For larger boilers, equipment and installation costs are somewhat higher. Payback is about 1- 2 years, depending on the installation costs.

For further information, please refer to the website below:
http://www.energysolutionscenter.org/boilerburner/Eff_Improve/Efficiency/Oxygen_Control.asp

Operator Training is necessary to ensure that operators are knowledgeable of the best practices in boiler operation. It is important that all boiler operators undergo some level of training in safe and efficient operation of the boiler, and it is a requirement that Licensed Boiler Operators and Stationary Engineers undergo specific training for their license. On October 4, 1994, USEPA had published a model state training and certification program in the Federal Register for the training and certification of solid waste incinerator unit operators and high-capacity fossil fuel-fired plant operators. In 1994, The American Society of Mechanical Engineers (ASME), at the request of USEPA, established a committee which developed standards for the qualification and certification of high capacity fossil fuel-fired plants. The application for an ASME certification program is available at

http://files.asme.org/asmeorg/Codes/CertifAccred/Personnel/2971.pdf

Also, most of the major boiler manufacturers and the American Boiler Manufacturers Association (www.abma.org) offer operator training. Training is also available through private companies (for example, American Trainco). Although Illinois EPA has not developed its own operator training and certification program; however, the proposed rule requires an employee of the owner or operator or a contractor who has successfully completed a training course to perform the combustion tuning.

Boiler Maintenance is necessary for proper operation of a boiler. All boilers suffer some degradation in performance as the result of deposits on heat transfer surfaces, corrosion, and general wear and tear. Boiler manufacturers set year-round maintenance schedules for tuning-up of boilers. The maintenance is aimed at corrective and preventive measures to maximize boiler efficiency and reliability. These measures are performed on periodic basis.

It is important that a boiler operator has written procedures for inspection and maintenance/ repair, and testing of the following on a periodic basis:

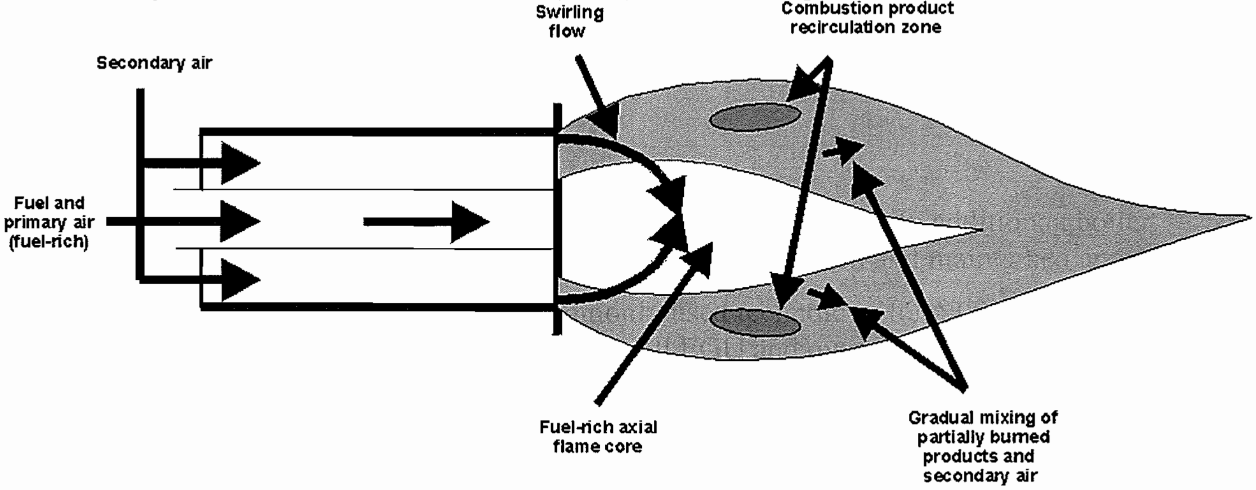
- Fireside and water-side surfaces: Scale build up on water side and soot build up on gas side.
- Fuel systems: Burners, atomizers, flame pattern, fuel pressure and temperature at the burner, coal feeders, grates, air-proportioning dampers, coal-size etc.
- Electrical and combustion control systems including safety interlocks, air dampers, control linkages etc;
- Excess oxygen, CO, and CO2 levels in the exhaust gases, as necessary, to calculate combustion efficiency and make necessary adjustments to the combustion system;
- Valves (relief, safety, hydraulic, pneumatic, etc.);
- Refractories;
- Fan housing, blades, and inlet screens;
- Feedwater system

These procedures must be followed and records must be kept on site. In addition, a boiler operator must prepare a checklist of items which must be inspected and maintained annually.

Low NOx Burners (LNB) are the most commonly used technology for NOx control on pulverized coal, gas and oil fired boilers. Nearly all EGU and over 75% of industrial boilers have LNB installations for reducing NOx emissions. Figure 2-8 shows a simplified example of an LNB using air staging. The primary air and fuel are combined in an overall fuel-rich (more fuel than the air can completely react with) zone. In this oxygen starved zone, fuel nitrogen is released and is converted primarily to molecular nitrogen. Secondary air is added in a controlled fashion to complete fuel burn out while maintaining oxygen concentrations and temperatures low. This limits formation of thermal NOx. Typically, LNB reduce NOx formation by as much as 65%, depending on the type of fuel used for combustion. As technology has improved, the control capabilities of LNB have continued to improve over the years, with current burners capable of much better performance than the LNB employed ten years ago. In fact, it is not uncommon for companies to replace their ten year old LNB with newer ones that provide improved performance (lower NOx, better combustion efficiency, etc.). The latest generation of LNB are capable of much lower emissions than LNB's of ten or so years ago perhaps 50% lower NOx emissions than first-generation LNB. It is not unusual for pulverized coal facilities firing PRB coal to have NOx emissions under 0.15 lb/MMBtu on low NOx burners, especially when combined with overfire air. In fact, several tangential-fired EGUs in Illinois already achieve these levels or better. On bituminous coal, somewhat higher emissions can result. But, they nevertheless are significantly improved over older burner designs.

The cost of LNB for reducing NOx generation from ICI boilers is dictated primarily by retrofit/capital costs. Operation and maintenance (O & M) cost is generally low.

Figure 2-8. A Low NOx Burner (LNB) that uses staged combustion air (SCA)



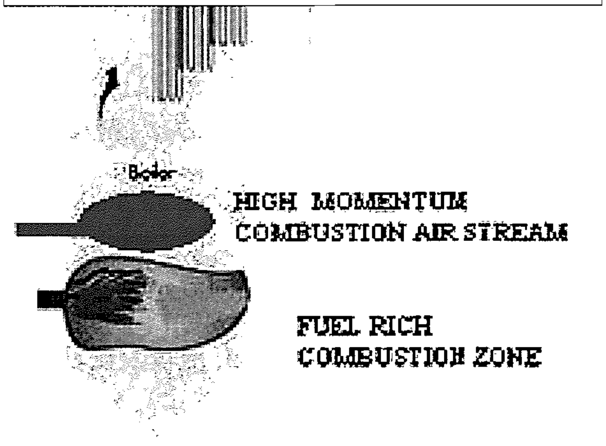
The most effective way of controlling thermal NOx is by controlling peak flame temperature, which can be controlled by quenching the flame with water or steam injection (WI/SI), or by reducing air preheat (RAP), or by recycling a portion of flue gas to the burner zone (flue gas recirculation, or FGR). WI/SI and RAP introduce thermal efficiency penalties, safety, and burner control problems. So, it is unattractive for large boilers. FGR, on the other hand, is widely used alone or in combination with LNB retrofits on gas or oil-fired boilers where flue gas does not have a high particle loading. The main disadvantage of FGR is increased capital cost for external ducting. External FGR also increases the flow rate through the boiler, which may be limiting. However, newer LNB designs have internal FGR, which achieves much of the same effect as external FGR, but without the need for external ductwork and increasing flow rate through the boiler.

Other approaches that provide modest reductions in NOx and may be used alone or in combination with LNB are oxygen trim (OT) and/or low excess air (LEA). Thermal NOx can be reduced to some extent by minimizing excess oxygen, delaying the mixing of fuel and air and reducing the firing capacity of the boiler. By optimizing the burner(s) for minimum excess air, it is possible to reduce NOx emissions by 5 to 20 percent, but this may increase CO emissions. This technique is often referred to as OT or LEA and can be attained by optimizing the operation of the burner(s) for minimum excess air without excessive increase in CO or other combustible emissions. The effect of lower oxygen concentration on NOx is partially offset by some increase in thermal NOx because of higher peak temperature with lower gas volume. The rapid increase in CO emissions is indicative of reduced mixing of fuel and air that result in loss of combustion efficiency. Boiler operation with LEA is considered an integral part of good combustion air management that minimizes dry gas heat loss and maximize boiler efficiency. Therefore most boilers should be operated with LEA regardless of whether NOx reduction is an issue.

The second technique reduces flame temperature and oxygen availability by staging the amount of combustion air that is introduced in the burner zone. *Staged combustion air ("SCA")* can be accomplished by several means. For multiple burner boilers that have the ability to operate with fewer than all of their burners in operation, one approach is to take certain burners out of service ("BOOS") or biasing the fuel flow to selected burners to obtain a similar air staging effect. By and large, LNB are more effective than BOOS. And, BOOS can be very limiting on boiler operation.

Overfire Air (OFA) is often used to allow deeper air staging. In OFA the burners are operated with lower excess air, or even fuel rich, and air is admitted downstream (typically at a higher point in the furnace) to burn out the fuel, as shown in Figure 2-9. OFA is also shown in Figure 2-6 on a CFB boiler. However, OFA cannot be used on every boiler because some boilers, such as many package boilers, do not have the space available between the combustion zone and convective heat exchangers to allow for OFA.

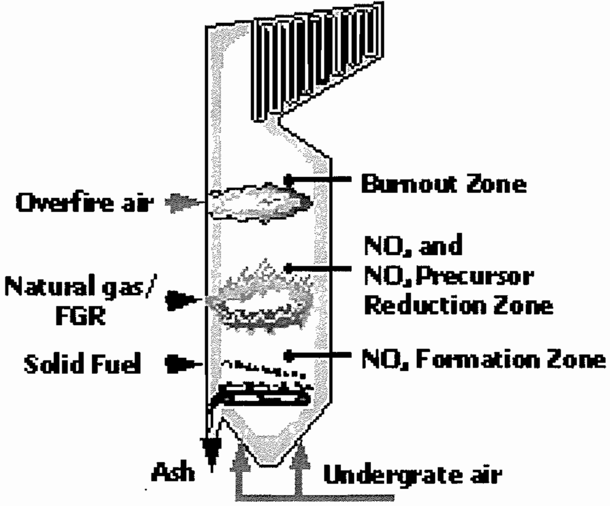
Figure 2-9. Overfire Air (OFA)
http://www.advancedcombustion.net/overfireair.htm



Fuel staging, such as employed in natural gas reburn (NGR – shown in Figure 2-10) and cofiring, are effective techniques for controlling NOx emissions from coal-fired stokers. By injecting a portion of total heat input downstream of main combustion zone, hydrocarbon radicals created by reburning fuel will reduce NOx emissions generated by the combustion of primary fuel.

Alternative methods have also been designed to reduce NOx emissions. Air Liquide devised a fuel "pulsation" approach that causes alternating fuel rich/lean mix conditions to occur at the burners. The lean mix condition reduces flame temperature and ultimately reduces thermal NOx. The fuel rich condition produces high VOC and CO, also minimizing NOx generation. Air is injected downstream of the flame to produce complete combustion. The modification demonstrates reductions of 35 – 65% without the use of FGR. With FGR NOx emissions below 20 ppm are achieved. Cost estimates for the modification are claimed to be 30 – 50% lower than installing replacement burners.[5]

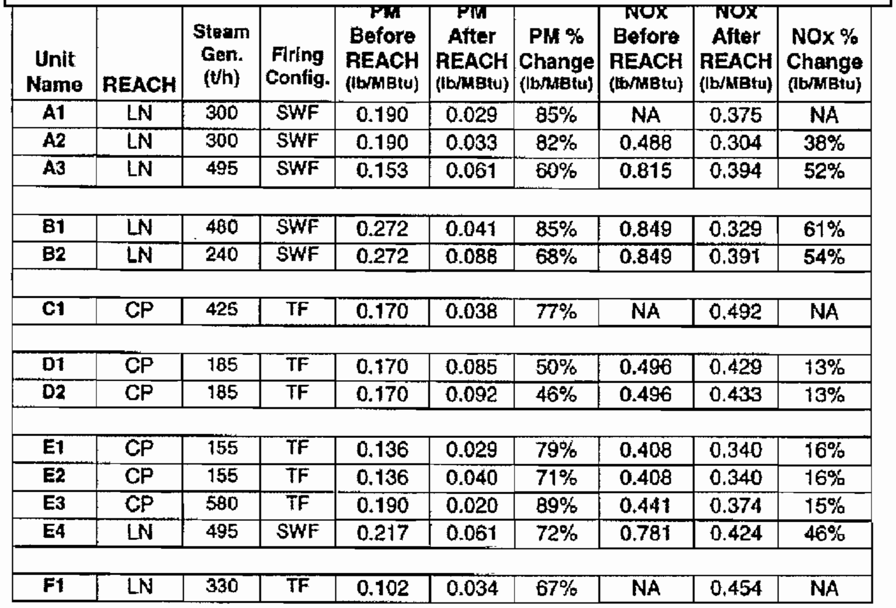
Figure 2-10. Natural gas reburning on a stoker boiler.
http://www.gastechnology.org/webroot/app/xn/xd.aspx?it=enweb&xd=4reportspubs%5C4_8focus%5Cmethanedenoxforstokerboilersfocus.xml



Burner Modifications

Burners may be modified to achieve low NOx in lieu of new burners. This is usually much less expensive than new burners, and this approach has been widely used on oil-fired burners. One such technology for oil fired burner modifications is Reduced Emissions and Advanced Combustion Hardware (REACH), which entails the use of new atomizers and flame stabilization devices on the burner. As shown in Table 2-7, significant reductions in NOx and particle matter are possible through REACH technology. REACH technology is estimated to cost as shown in Figure 2-11. Assuming about 1200 BTU per pound of steam, the costs on Figure 2-11 (1998 dollars) should be divided by 2.4 to arrive at the approximation for cost in $/MMBtu/hr. The unit capacity in t/hr would then be multiplied by 2.4 to arrive at the capacity in MMBtu/hr. So, a 200 t/hr (or about 500 MMBtu/hr) boiler would be expected to cost in the range of $360/t/hr (or about $150/MMBtu/hr)

Table 2-7 PM and NOx Emissions with REACH Technology
http://www.coen.com/i_html/white_lowcostnoxpm.html



Unit Name	REACH	Steam Gen. (t/h)	Firing Config.	PM Before REACH (lb/MBtu)	PM After REACH (lb/MBtu)	PM % Change (lb/MBtu)	NOx Before REACH (lb/MBtu)	NOx After REACH (lb/MBtu)	NOx % Change (lb/MBtu)
A1	LN	300	SWF	0.190	0.029	85%	NA	0.375	NA
A2	LN	300	SWF	0.190	0.033	82%	0.488	0.304	38%
A3	LN	495	SWF	0.153	0.061	60%	0.815	0.394	52%
B1	LN	480	SWF	0.272	0.041	85%	0.849	0.329	61%
B2	LN	240	SWF	0.272	0.088	68%	0.849	0.391	54%
C1	CP	425	TF	0.170	0.038	77%	NA	0.492	NA
D1	CP	185	TF	0.170	0.085	50%	0.496	0.429	13%
D2	CP	185	TF	0.170	0.092	46%	0.496	0.433	13%
E1	CP	155	TF	0.136	0.029	79%	0.408	0.340	16%
E2	CP	155	TF	0.136	0.040	71%	0.408	0.340	16%
E3	CP	580	TF	0.190	0.020	89%	0.441	0.374	15%
E4	LN	495	SWF	0.217	0.061	72%	0.781	0.424	46%
F1	LN	330	TF	0.102	0.034	67%	NA	0.454	NA

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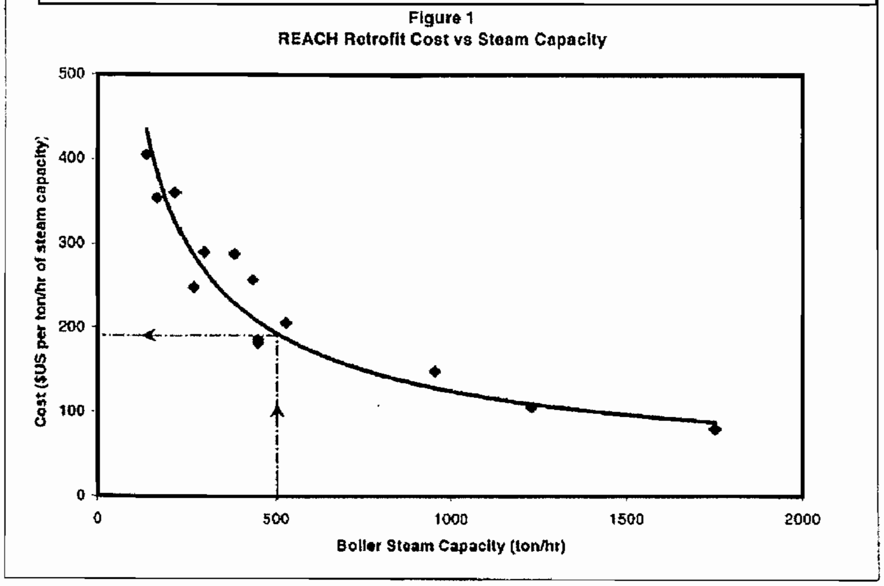
[5] Rajani Varagani (n.d.). "A Cost Effective Low NOx Retrofit Technology for Industrial Boilers." Cited within CIBO Industrial Emissions Control Technology III, 2005

to retrofit with REACH technology. Current prices (2007 dollars) would be higher. However, they would still be well below the cost of new burners (up to about $5000/MMbtu/hr installed in 2007 dollars). The cost of a complete burner retrofit could be three to ten times as expensive as a retrofit of REACH technology, and the difference would be greater if the greater outage costs of a burner retrofit were considered.

Figure 2-11. REACH Retrofit Cost Versus Steam Capacity
http://www.coen.com/i_html/white_lowcostnoxpm.html



More recent information available from Combustion Components Associates (CCA) shows that even better results are possible with heavy oil firing than presented above, as shown in Table 2-8. Cases 6 and 7 are utility units, but they are shown because some of the largest industrial units may approach these in size. For wall-fired units without OFA, an average emissions rate of 0.25 lb/MMBtu was achieved with only burner modifications (change of burner atomizers and swirlers, if needed). In all cases opacity dropped significantly as a result of the retrofit. Addition of OFA on a wall-fired unit enabled an emissions rate of under 0.15 lb/MMBtu. According to information provided by CCA, the total cost of such retrofits would be in the range of $200/MMBtu/hr to about $500/MMBtu/hr.[6]

Table 2-8. Case Studies of No. 6 Oil Fired Boilers[7]

Case #	Rating		# Burners	Init NOx	FinNOx	% Reduction
	Kpph	~MMBTU/hr		lb/MMBtu		
1*	50	60	1	037	0.27	27%
2*	120	144	1	0.325	0.26	20%
3*	175	210	4	0.34	0.27	21%
4*	425	510	4	0.40-0.45	0.20-0.25	50%
5*	600	720	8	0.35-0.40	0.20-0.25	40%
6* 6**	125 MW	1,250	12	0.43 0.43	0.26 1.145**	40% 66%
7***	160 MW	1,600	12	0.42	0.225	54%

* wall fired without OFA
** wall fired with OFA added
*** Tangentially Fired, no OFA

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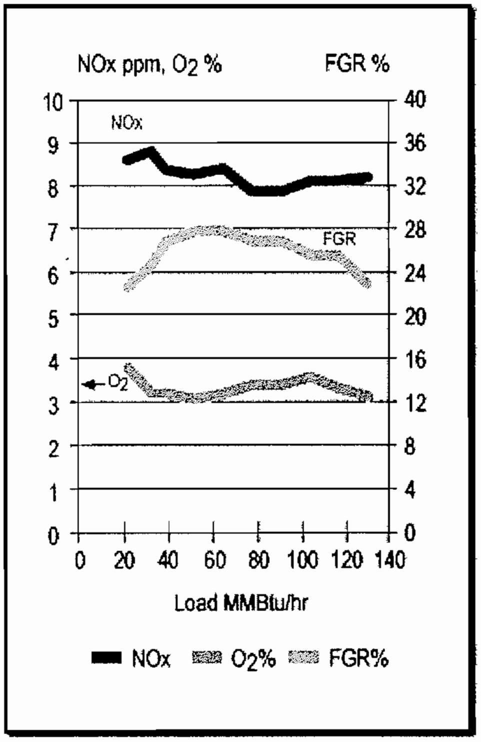
[6] Based on estimate for a 4-burner project from Combustion Components – e-mail 10/13/03

[7] Combustion Components Associates Website: http://www.ccainc.net/case_study/case_studies.htm

Lean Premixed Combustion and Ultra Low NOx Burners

Figure 2-12 Emissions Performance of Todd Rapid Mix Burner at Morningstar Cannery
www.johnzink.com



Gas and volatile fuels offer the potential to use Lean Premixed Combustion (LPC). LPC is only used with volatile fuels that are low in nitrogen content and inherently have low fuel NOx formation, such as natural gas. In lean premixed combustion the fuel and air are premixed thoroughly before ignition into a fuel-lean mixture. Combustion occurs under well-controlled conditions with excess air while maintaining temperature low. This approach minimizes formation of thermal NOx by controlling temperature and oxygen carefully. Prompt NOx formation is minimized by maintaining conditions with excess oxygen. This method of combustion is capable of producing NOx emissions in the single digit levels, even with air preheat.

Most of the LPC burners that are available have demonstrated emissions levels near or under 0.01 lb/MMBTU when using flue-gas recirculation. Figure 2-12 shows the performance of a 130 MMBtu/hr Todd Combustion Rapid Mix Burner that was retrofit on a 100,000 lb/hr Nebraska water-tube boiler.[8] Some retrofit applications have already demonstrated under 0.01 lb/MMBtu (about 8 ppm at 3% oxygen with natural gas fuel) with air preheat while improving boiler efficiency. [9] However, experience at one boiler does not necessarily translate to similar experience at another. And, 0.01 lb/MMBtu may not always be achievable with LPC when there is air preheat. This is because factors such as heat release rate of the boiler and other effects can impact the actual burner performance.

Table 2-9 shows results from three applications of the Todd Rapid Mix Burner.

Another supplier of burners with ultra-low NOx using LPC is Coen. Its burner has been installed at a California facility with burners permitted for 30 ppm NOx. The boiler was the main boiler with a continuous rate of 60,000 pph of 250 psig saturate steam. The preheat air is heated up to 425°F and FGR is supplied to side-by-side burners by a forced draft fan.

The results at this site show that the new ULNB system has reduced NOx levels below 7.5 ppm @ 3% oxygen. Table 2-10 summarizes the pre and post retrofit numbers for NOx, CO, and O_2, while Table 2-11 shows the cost estimates for various parts of the installation and operation of the Quantum Low NOx (QLA) burners.

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[8] http://www.johnzink.com/products/burners/html_todd/burn_todd_cs_104.htm

[9] Sacramento General Services Heating Plant Case Study: COEN web site: http://www.coen.com/mrktlit/brochures/pdf/qla.pdf

Table 2-9. Performance of Todd Burner Using Lean Premixed Combustion at Three facilities

US BORAX TODD ULTRA LOW EMSSIONS BURNER INSTALLATIONS[10]			
LOAD %	O_2%	CO ppm	NOx ppm
25	3.4	3.0	8.2
53	2.6	0.9	7.1
98	2.7	0.1	6.8
MORNINGSTAR TODD ULTRA LOW EMISSIONS BURNER INSTALLATION[11]			
LOAD %	O_2%	CO ppm	NOx ppm
25	3.4	<1	8.1
50	3.4	<1	8.2
100	3.2	<1	8.3
TODD ULTRA LOW EMISSIONS BURNER INSTALLATION[12]			
LOAD %	O_2%	CO ppm	NOx ppm
20	4.8	2	8
50	3.5	3	7
90	3.4	6	7

Table 2-10. Performance of Coen QLA burner using LPC. [13]

	Units	Run 1	Run 2	Run 3	Run 4
Stack Levels					
O2	%	6.0	6.1	6.1	6.1
CO	ppm, 3% O2	3.5	2.7	2.7	2.9
NOx	ppm, 3% O2	7.3	7.6	7.6	7.5

Table 2-11. Cost estimates for various parts of the installation and operation of the QLA burners on a 61,000 pph boiler (roughly 80 MMBtu/hr).[13]

Cost item	Units	QLA
Capital Costs		
Hardware Costs	$	170,000
Installation Costs	$	68,000
Installed Capital Cost	$	238,000
Annualized Capital Cost	$/yr	27,955
Operating Cost		
Increased Fan Power	$	35,000
Total	$/yr	35,000
Total Annual Cost	$/yr	62,995

Assuming the 60,000 lb/hr boiler is roughly 72 MMBtu/hr, this cost is roughly $3300/MMBtu. This cost is roughly consistent with other sources that indicate that for large ICI boilers (typically over 100 MMBtu/hr) the cost of Low NOx burners on industrial boilers will be about

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[10] Zink, John (2003). "U.S. Borax TODD Ultra Low Emissions Burner Installment."

[11] Zink, John (2003). "Morningstar TODD Ultra Low Emissions Burner Installment."

[12] Zink, John (2003). "TODD Ultra Low Emissions Burner Installment."

[13] Coen Company (2000). "Ultra Low NOx Gas-Fired Burner with Air Preheat." Prepared for California Air Resources Board. CARB Contract #: 94-354, Nov 23, 2000.

$2,000/MMBtu/hr to $2,500/MMBtu/hr because one would expect a lower cost for the larger units and especially one without FGR. The burner itself is generally a small part of this cost. For field-erected boilers that may use multiple stages of Separated Overfire Air (SOFA) downstream of low NOx diffusion flame burners, and also use FGR, the total cost for all equipment and boiler modifications could be as high as $3,500/MMBtu/hr.[14]

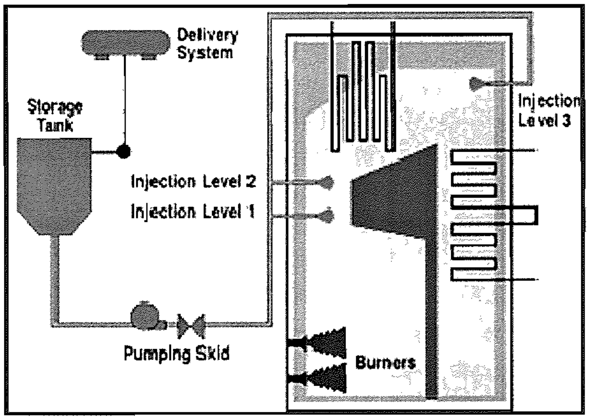
2.3.2 Post Combustion Controls:

Selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) techniques are the only two post combustion techniques which have been applied to control NOx emissions from ICI boilers. In both these techniques, urea or ammonia is injected in a temperature window where NOx reduction occurs by selective reaction of NH_2 radicals with NO to form water and nitrogen. By-product emissions of SNCR include ammonia slip and N_2O. In the SCR process, ammonia is injected into the flue gas in the presence of a catalyst and NOx is converted to N_2 and H_2O.

2.3.3 Selective Non-Catalytic Reduction (SNCR)

Figure 2-13. Simplified diagram of an SNCR system.

(www.wapc.com)



SNCR has been widely used on ICI and EGU boilers, especially boilers with solid fuels. SNCR is a process that uses ammonia or urea reagents to selectively reduce NOx to nitrogen and water without the presence of a catalyst. Since this technology does not use any catalyst, it can be implemented at much lower capital costs compared to catalyst based technologies. The equipment is comprised of a storage tank, pumping equipment, piping and injectors, as shown in Figure 2-13, and it is relatively easy to retrofit on existing facilities. The reagent is injected where the gas temperature is optimal to promote the reaction with the minimal amount of unreacted ammonia. This optimum temperature window varies somewhat based upon the application. But, it is in the range of 1600° to 2000°F for ammonia based and 1650° to 2100°F for urea based SNCR.

SNCR applications were first used in 1974 and there are currently 400 systems installed worldwide. This type of system can be used on a variety of industries such as the pulp/paper, steel industry, refinery process, cement kilns, municipal waste combustors, process heaters, glass melting furnaces, wood/coal/oil/gas-fired boilers.[15] Table C-1 in the Appendices is a list of SNCR systems from only one supplier.

The two principal reagents used in the SNCR process are ammonia (NH_4OH) and aqueous urea (NH_2CONH_2). In large boilers and where load changes significantly, several injection locations

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[14] (Memo: J. Staudt to Sikander Khan, USEPA, October 24, 2003 comments in response to September 10, 2003 email)

[15] Institute of Clean Air Companies (2006). "Selective Non-Catalytic Reduction Technology Costs for Industrial Sources." Letter from ICAC to OTC [Ozone Transport Commission].

are necessary in order to inject the reagent into the proper temperature zone. The amount of urea or ammonia injected in the furnace varies with the NOx reduction target and uncontrolled NOx level.

Tables 2-12a and 2-12b provide NOx reduction performance information of ammonia and urea SNCR from the 2000 NESCAUM report on NOx control technologies. As can be seen from the table, SNCR is quite effective in controlling NOx emissions from a range of industrial boilers. Table 2-13 shows the cost of SNCR on wood-fired boilers. The capital cost of SNCR on coal-fired boilers of similar size (MMBtu/hr) as the wood-fired boilers in Table 2-13 would be expected to be about the same. According to Tables 2-12a and 2-12b, the average NOx reduction for every boiler category exceeded 50%, with some well over 70%. As a result, it would be reasonable to expect 50% NOx reduction using SNCR on average.

For EGU's SNCR capital cost is in the range of about $15/KW, and in most cases NOx reductions in the range of about 30% are possible.[16]

Table 2-12a Statistics Regarding Performance of Industrial Boiler Types Equipped with Urea SNCR [17]

NOx Performance Statistic	Wood Fired IPP	Pulp/Paper	Refining	Industrial	Steel Industry
Avg NOx Red	51%	52%	57%	53%	74%
Std Error of Mean	1.9%	2.4%	3.6%	2.8%	6.2%
Pop. Std Dev.	8.3%	7.9%	14.0%	9.7%	20.5%
Min	35%	35%	34%	40%	30%
Max	70%	62%	74%	70%	90%
# Facilities	19	11	15	12	11
Fuels	Biomass Wood/Coal	Wood waste, Wood, pulp, oil, black liquor	Ref. Gas Pet Coke Nat. Gas	Coal, #6 Fuel Oil	Coal Nat. Gas

- Avg NOx Red is the arithmetic average of the NOx reductions reported.
- Std Error of Mean is the measure of the uncertainty in using the sample mean to estimate the mean of a large population. When it is small relative to the mean, this indicates that the mean is a good measure.
- Pop. Std Dev. Is the estimated standard deviation of a large population - a measure of dispersion
- Minimum is the minimum value reported
- Maximum is the maximum value reported

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[16] Northeast States for Coordinated Air Use Management (NESCAUM), "Status Report on NOx – Control Technologies and Cost Effectiveness for Utility Boilers", 1998

[17] Northeast States for Coordinated Air Use Management (NESCAUM), "Status Report on NOx – Control Technologies and Cost Effectiveness for Industrial Boilers, Gas Turbines, IC Engines, and Cement Kilns", 2000

Table 2-12b Statistics Regarding Performance of Industrial Boiler Types Equipped with Ammonia SNCR [17]

NOx Performance Statistic	**Stoker**	**Stoker**	**CFB/BB**	**Industrial**	**Refin. Heaters**
Avg NOx Red	61.7%	57.5%	78.3%	57.7%	58.75%
Std Error of Mean	2.2 %	3.1%	0.81%	3.5%	3.35%
Std. Dev.	7.3%	8.8%	2.1%	11.7%	9.5%
Min	57%	46%	76%	30%	43%
Max	78%	75%	80%	75%	70%
# Facilities	11	8	7	11	8
Fuels	Coal	Biomass	Coal, Biomass	Gas/Oil	Refinery Gas, Nat. Gas, Oil

- Avg NOx Red is the arithmetic average of the NOx reductions reported
- Std Error of Mean is the measure of the uncertainty in using the sample mean to estimate the mean of a large population. When it is small relative to the mean, this indicates that the mean is a good measure.
- Pop. Std Dev. Is the estimated standard deviation of a large population - a measure of dispersion
- Minimum is the minimum value reported
- Maximum is the maximum value reported
- CFB/BB means Circulating Fluidized Bed or Bubbling Bed boilers

Table 2-13 Reported Cost of Urea SNCR for Wood-Fired Power Boilers[17]

Size, MMBTU/hr	Type	% Reduct.	Capital $	Estimated Ann. Oper. $	Baseline NOx
900	Grate-Fired Biomass	50%	$1.1 M	$230 K	235 ppm
475	CE Stoker	60%	$700K	$54 K	0.47 lb/MMBTU
300	Riley Stoker	30-50%	$600K	$40K	0.25 lb/MMBTU
245	Front Fired Fiber Waste	50%	$390K	$58 K	370 ppm

* note: Capital cost shown is equipment, engineering, commissioning, but not installation. Installation typically adds around 20% to 30% to the cost.
Also, coal-fired boilers of similar heat input would be expected to have similar capital cost.

Capital costs, and the resulting impact to cost-effectiveness (in $/ton of NOx removed), are impacted by facility size. Figures 2-14a and 2-14b illustrate the difference in Cost Effectiveness (in $/ton of NOx removed – calculated annually and for the ozone season) and capital cost for fifty industrial installations. Not surprisingly, control is more expensive (normalized to unit size or in terms of $/ton of NOx removed) for smaller boilers than for larger boilers. Thus, in most cases NOx can be controlled more cost effectively with SNCR on larger units than smaller units.

The cost curve for the fifty applications analyzed indicates that the majority of the ozone season applications have cost effectiveness values less than $4000/ton even for smaller units. An even greater percentage of the applications have cost effectiveness values less than $3000/ton for annual operation of the SNCR technology. For units over 100 MMBtu/hr, the units generally have a cost effectiveness of under $2500/ton on an annual basis.

Figure 2-14a. Cost Effectiveness of Fifty SNCR Systems on ICI boilers. [15]

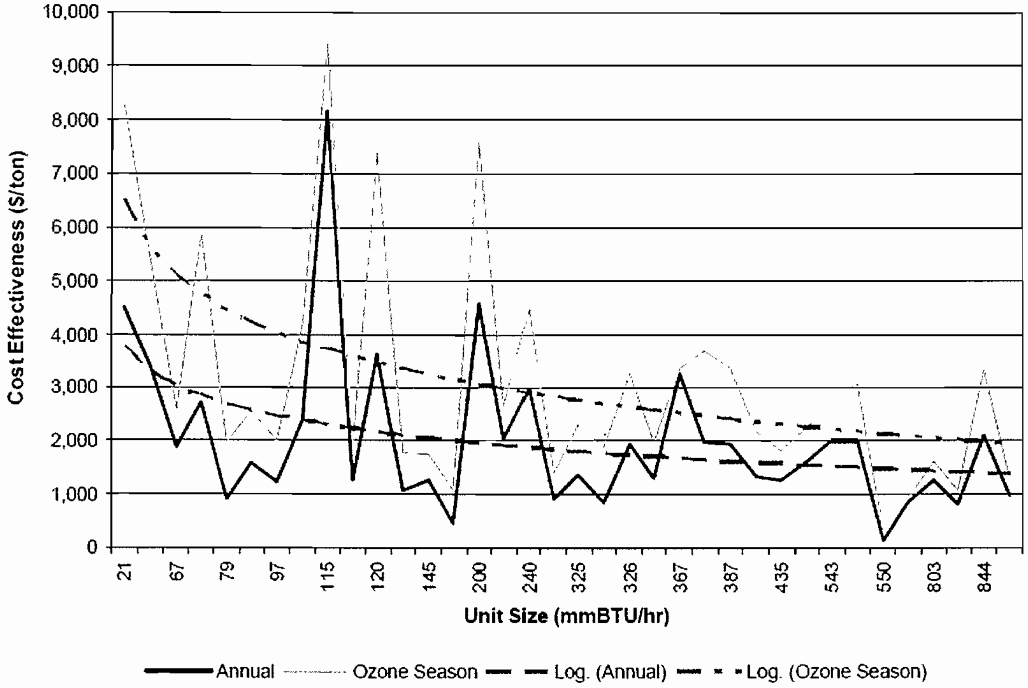
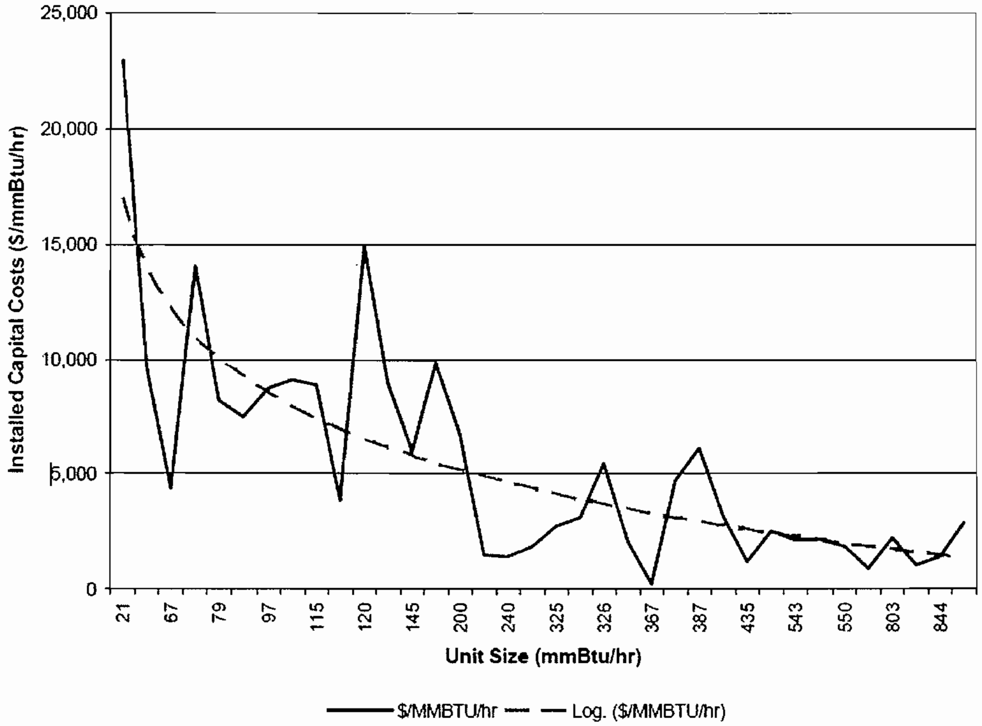


Figure 2-14b. Installed Capital Cost of SNCR on 50 ICI Boilers15



As shown in Figures 2-14a and 2-14b, for ICI boilers greater than 100 MMBtu/hr, capital cost is typically $7,500/MMBtu or less, or about $750,000 for a 100 MMBtu/hr boiler. There are economies of scale inherent to SNCR capital cost on ICI boilers in this size range. On a $/MMBtu/hr basis, larger boilers tend to be less expensive to retrofit with SNCR. For example, a 900 MMBtu/hr boiler might entail a retrofit cost of $1000-$2000/MMBtu/hr, or about $900,000 to $1.8 million – not that much more than the 100 MMBtu/hr boiler, despite the much larger size.

2.3.4 Selective Catalytic Reduction (SCR)

Interest in SCR for NOx reductions on a variety of combustion sources has grown substantially in recent years. SCR technology can reduce NOx emissions in excess of 90%. Commercially, SCR is typically utilized in situations where combustion NOx controls are not adequate to reduce NOx to the desired emissions levels. The technology has been used for many years on gas, oil, and coal-fired boilers and gas turbines. There are several SCR installations on utility coal-fired utility boilers in Illinois. SCR has also been operated on several coal-fired electric utility boilers in other states.

The SCR process is based on the selective reduction of NOx by NH_3 over a catalyst in the temperature range of 500° to 900°F. The catalyst lowers the activation energy required to drive the NOx reduction to completion, and therefore decreases the temperature at which the reaction occurs. Contrary to the SNCR process, both NO and NO_2, the two principal forms of NOx from power plants are reduced to N_2. In the SNCR process only NO is affected. Also N_2O is not a significant by-product of the SCR process, where as N_2O can be as much as 25 percent of the NO reduced in the SNCR process. The overall SCR reactions are:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6\,H_2O$$
$$8NH_3 + 6NO_2 \rightarrow 7N_2 + 12H_2O$$

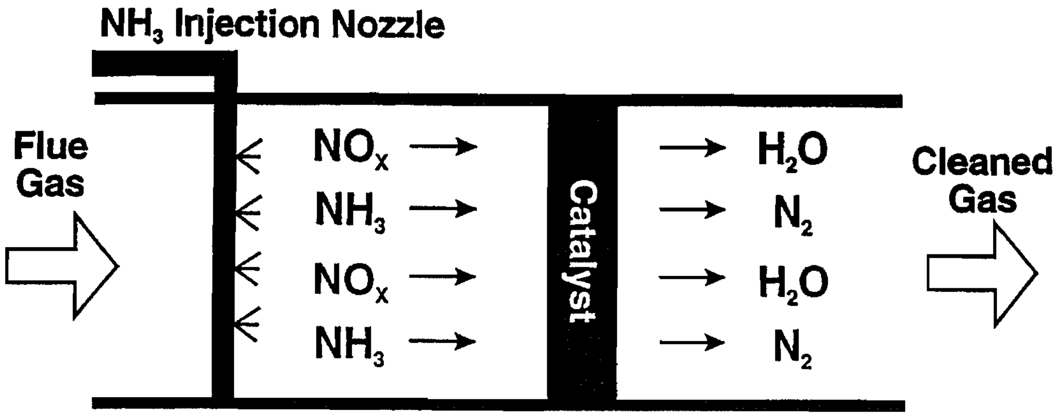
These are depicted in Figure 2-15.

Catalysts and substrates are shaped in either parallel or honeycomb modules that are stacked together in a reactor – in multiple levels in the case of coal boilers as in Figure 2-16 - that must be placed in the appropriate location where gas temperature matches the catalyst peak performance temperature. In the utility boiler, this temperature normally corresponds to the inlet air heater when the boiler is at or near full load. At the lower boiler loads, the temperature at the air heater inlet may drop sufficiently so that some amount of economizer bypass may be required to maintain the catalyst at the optimum temperature.

Application of SCR in high sulfur and high dust flue gas has been performed successfully in numerous utility boiler applications. For this reason, SCR is viewed as technically feasible for nearly any coal application.

For boilers, the most popular arrangements include: in-duct catalysts and full-scale reactor catalysts. In coal-fired applications, full-scale SCR reactors have been most common.

Figure 2-15. Simplified diagram of the SCR process [18]



The in-duct arrangement of SCR catalyst has been primarily used in boilers firing natural gas. The approach is to squeeze as much catalyst as possible within the existing duct space between the economizer and the air heater without having to move any of this equipment.

Full-scale SCR systems have been applied to numerous utility boilers burning coal and residual oil. There are three possible arrangements to place a SCR reactor within the existing equipment layout of a steam generator. The most popular arrangement, both in the U.S. and abroad is the hot side, high dust setup where the SCR reactor is placed ahead of the air heater and cold-side ESP. Although the SCR reactor is exposed to the full dust loading leaving the boiler, this arrangement often represents the most economic operation.

Because of the success of using SCR in utility boilers, there is good reason to believe that SCR is technically feasible on ICI boilers. However, in many cases the cost of retrofitting SCR on an ICI boiler will make it less attractive than other approaches for NOx control.

Figure 2-16. An SCR reactor for a coal-fired utility boiler
(Alstom Power SCR brochure)

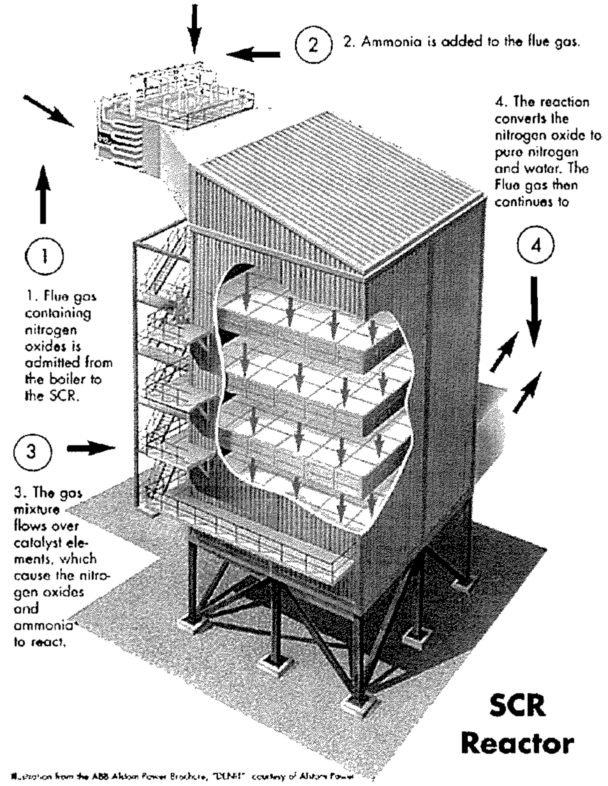


Illustration from the ABB Alstom Power Brochure, "DENIT" courtesy of Alstom Power

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[18] Institute to Clean Air Companies, "White Paper: Selective Catalytic Reduction (SCR) Control of NOx Emissions", November 1997

As previously noted, full-scale SCR systems have been applied to numerous utility boilers. SCR has been applied to a large number of other source categories as well. Table 2-14 displays the number of SCRs installed on a variety of boiler applications and fuel types for just one major SCR system supplier.

Table 2-14. SCRs installed on various applications from one US supplier[19]

Application	**Units**
Utility Boilers	189
-Natural Gas Fired	*54*
-Coal Fired	*132*
*-Oil Fired**	*1*
-Wood Fired	*2*
-Demonstration	*4*
Combustion Turbines	558
Diesel Engines	25
Refinery & Industrial Boilers	165
Total Units	**941**

http://www.cormetech.com/experience.htm

Preliminary estimates of capital and O&M costs for ICI boilers are highlighted in Table 2-15. These were developed by USEPA for comment. For coal-fired ICI boilers the capital cost range is from $3.5 – $5.25 million with an average annual operation cost of $105,000. EGU's, due to size, obviously cost more and are more expensive to run. ICI boilers that utilize oil, natural gas, and wood operate for approximately $158,000/year with a capital cost of $1.4 – $2.1 million. All ICI boiler costs were based on a capacity of 350 mmBtu/hr.

Unfortunately, cost estimates using 1999 base data are not truly accurate. Due to recent escalation of the cost of capital-intensive emission control technologies, such as SCR and wet FGD, it is necessary to re-evaluate these costs in light of escalation. Using the Vatavuck index for wet scrubber costs published in Chemical Engineering magazine as an indicator for escalation from 1999 to 2007, it is estimated that capital costs have increased roughly by 50% since 1999.[20]

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[19] http://www.cormetech.com/experience.htm

[20] "Economic Indicators" Chemical Engineering, September, 2006, p 102, and Vatatuck, William M., "Updating the CE Plant Cost Index", Chemical Engineering, January 2002, p. 69

Table 2-15. Preliminary Capital and Operating Costs (1999 $) for ICI boilers equipped with SCR[21]

These results are based upon a preliminary evaluation by S. Khan of USEPA using AirControl net

Unit Type	**Capital Cost ($/MMBtu/hr)**	**O&M Cost ($/MMBtu/hr/yr)**	**$/ton of NOx Removed**
Industrial Coal, 350 MMBtu/hr	$10,000-$15,000	$300	$2,000-$3,000
Industrial Oil, 350 MMBtu/hr	$4,000-$6,000	$450	$1,000-$3,000

While there is no doubt that SCR is technically feasible on ICI boilers, there is some uncertainty regarding the cost because there is no data available on actual retrofit of coal-fired ICI boilers with SCR. So, it is necessary to rely on estimates. Assuming that costs have escalated 50% from 1999, this would increase the cost range of Table 2-15 for coal fired ICI boilers from $10,000-$15,000/MMBtu/hr to roughly $15,000-$22,500/MMBtu/hr. Using this range, an assumption of 90% NOx removal,[22] and assumptions regarding operating costs, it is possible to develop a revised, or updated cost estimate. Also, to see the effects of a significantly higher cost in the event of a very difficult retrofit, a cost estimate was also made assuming a capital cost of $30,000/MMBtu/hr. This high capital cost is to account for the possibility of an extremely difficult retrofit. Operating costs assume $400/ton for ammonia used and $7000/m^3 for SCR catalyst and $100,000/year of Fixed Operating Costs. For a boiler that operates 7000 hours per year with baseline emissions ranging from 0.40 to 0.60 lb/MMBtu, the costs are estimated to be per Figure 2-17. As shown in Figure 2-17, costs in $/ton are generally around $2500/ton or less except for the most conservative capital cost estimate of $30,000/MMBtu/hr where costs in $/ton are generally near or above that cost. Assuming a power plant heat rate of 10,000 Btu/KWh, a capital cost of $30,000/MMBtu/hr is roughly equivalent to $300/KW, which is the highest capital cost reported to be recently incurred for utility applications.[23] As a result, it is reasonable to use $30,000/MMBtu/hr as an indication of an extremely high cost, with capital cost in most cases likely to be less. Costs in $/ton of control are also affected by the baseline NOx level. Higher baseline NOx levels result in lower $/ton estimates.

However, the baseline NOx level has very little impact on actual total cost of SCR on the cost of owning and operating the facility, as shown in Figure 2-18. As shown in Figure 2-18, roughly a $0.40-$0.70/MMBtu of fuel input results from addition of SCR. In effect, if an owner is paying about $2.50/MMBtu for fuel (including all costs to deliver and prepare fuel), a $0.50/MMBtu cost associated with SCR is similar to a 20% increase in fuel cost for a 90% reduction in NOx emissions. Moreover, since the proposed rule allows for emissions averaging plans, and an SCR will provide lower emissions than required by the proposed rule, use of an SCR on a large boiler can mitigate the need for controls on other units. So, the actual impact when measured over all of the facilities that may receive the benefit of emission reductions from the SCR will be less than what is stated above.

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[21] "Controlling Fine Particulate Matter under the Clean air Act: A Menu of Options" dated March 2006. STAPPA/ALAPCO.

[22] Erickson, C., and Staudt, J., "Selective Catalytic Reduction System Performance and Reliability Review", presented at the EPRI-EPA-DOE-AWMA Combined Utility Air Pollution Control Conference, the Mega Conference, Baltimore, August 28-31, 2006

[23] Cichanowicz, E.J., "CURRENT CAPITAL COST AND COST-EFFECTIVENESS OF POWER PLANT EMISSIONS CONTROL TECHNOLOGIES", prepared for Utility Air Regulatory Group, June 2007

For EGUs, there is more data on the cost of SCR. Capital cost may be in the range of $150/KW for an EGU. However there is a wide variation in cost from unit to unit due to the level of difficulty associated with the retrofit. So, actual cost experienced for a particular project might be significantly greater or lesser. [23]

Figure 2-17. Estimated cost ($/ton of NOx removed) for a coal-fired ICI Boiler using SCR.

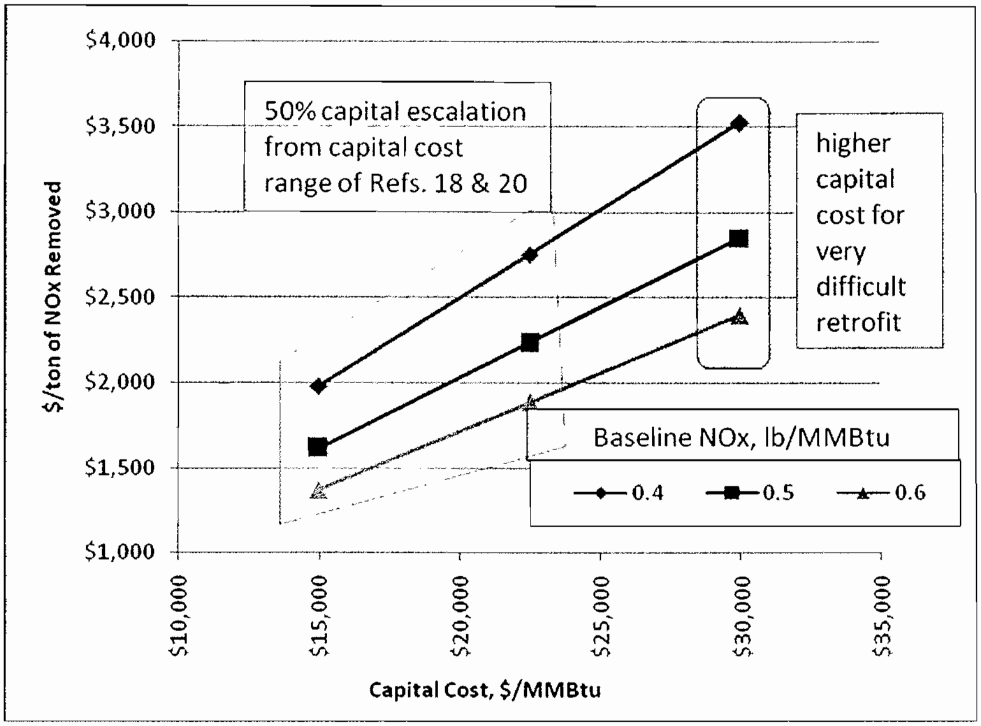
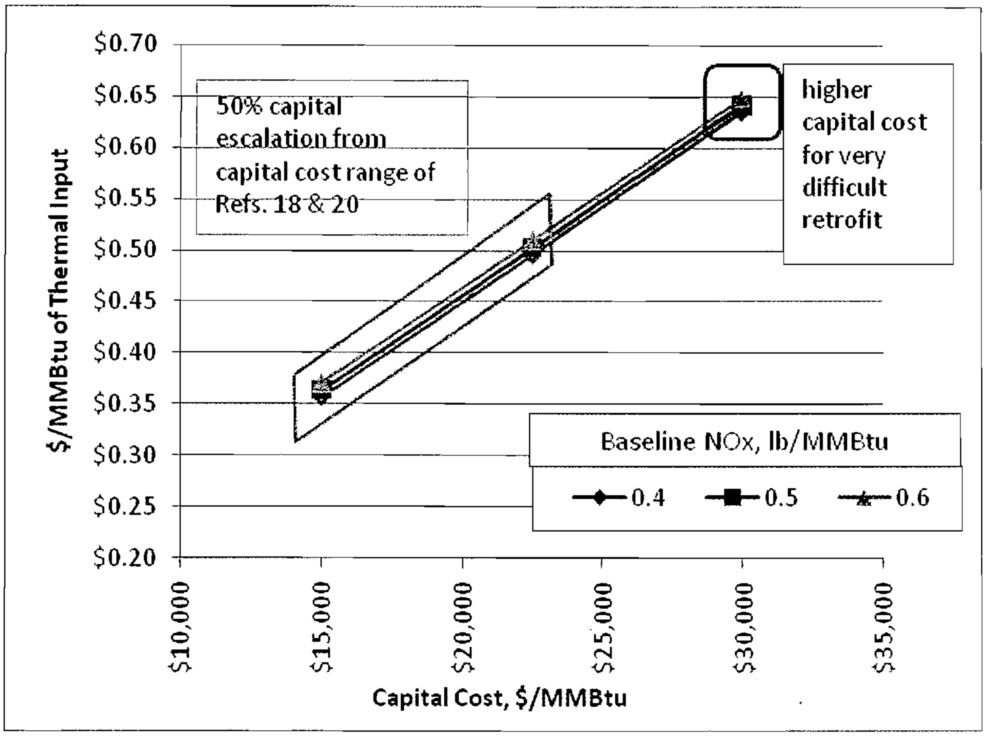


Figure 2-18. Estimated cost ($/MMBtu of fuel input) for a coal-fired ICI Boiler using SCR.

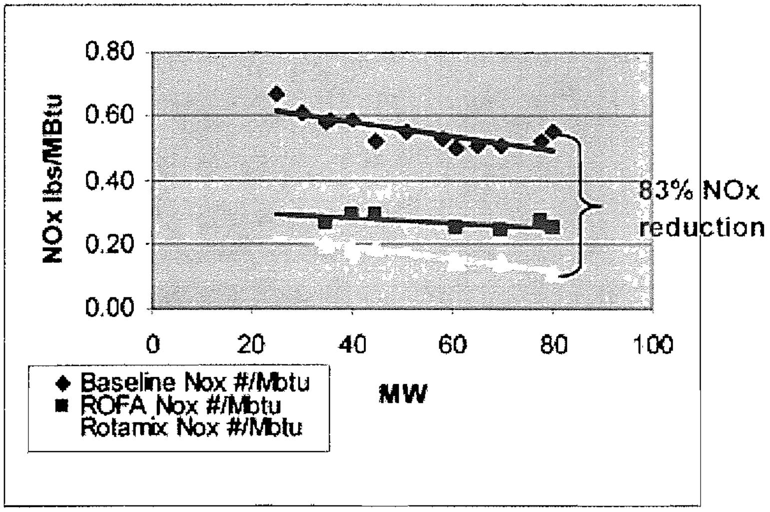


2.3.5 Fuel Switching

As discussed in the previous section, burning of fuel with lower fuel-bound nitrogen will generate lower NOx emissions. Natural gas and distillate oil have very low fuel-bound nitrogen content compared to residual fuel oil and hence switching from residual fuel oil to distillate fuel oil or natural gas will reduce substantially. Similarly, since coal has appreciable fuel-bound nitrogen, switching from coal to a cleaner burning fuel such as distillate oil or natural gas will lead to lower NOx emissions. Switching to a cleaner burning fuel, however, might entail significant capital and will usually increase fuel costs and therefore, fuel switching is likely to be unattractive.

2.3.6 Combinations of Controls

Figure 2-19. Rotamix results at Dynegy Vermillion Plant
http://www.mobotecusa.com/projects/vermillion-sellsheet.pdf



Frequently, combustion controls and post-combustion controls are combined to provide lower emissions and more cost-effective reductions than might be possible separately. A good example of this is Mobotec's combination of rotating overfire air (ROFA) and SNCR in its Rotamix technology. By combining these technologies, it is possible to reduce emissions from coal-fired boilers by 70%-80% or more in some cases. At Dynegy's Vermillion power plant in Illinois NOx emissions as low as 0.10 lb/MMBtu were achieved as shown in Figure 2-19. This is a small power plant that is similar to a large industrial boiler in size. Rotamix was also used at Progress Energy's Cape Fear #6 plant to achieve emissions levels of 0.18 lb/MMBtu or less at all loads, as shown in Table 2-16.

Table 2-16 . Rotamix results at Cape Fear 6
(http://www.mobotecusa.com/projects/capefear6-sellsheet.pdf)

Load (MW)	**NOx (lb/MMBtu)**	**% Redn**	**O_2**	**CO**	**NH_3 slip**	**Fuel**
62	014	82%	7.3%	< 30 pm	< 5 ppm	Bit. Coal
133	0.16	75%	3.4%	< 30 pm	< 5 ppm	Bit. Coal
174	0.18	71%	2.8%	< 30 pm	< 5 ppm	Bit. Coal

If Rotamix costs ~$4000/MMBtu in capital and achieves on average 75% reduction from about 0.5 lb/MMBtu, with the first 50% reduction from the combustion controls and the balance from SNCR, the cost of control is roughly $675/ton of NOx. This low cost is the result of the synergy of the two control technologies working together. Using a similar analysis for a boiler, perhaps firing residual fuel oil, with a baseline NOx level of 0.30 lb/MMBtu, it can be shown that NOx would be reduced at a cost of around $1,000/ton.

2.4 Cost Effectiveness of NOx Controls for ICI Boilers

According to the proposed rule, boilers equal to or smaller than 100 million Btu/hour and the emit 15 tons per year or more of NOx and 5 tons or more of NOx during the ozone season are required to perform combustion tuning (CT), which is expected to reduce NOx emissions by 5 to 35 percent. CT helps in fuel saving by improved combustion efficiency and reduced heat loss to the atmosphere. However, CT is relatively inexpensive.

Therefore, in estimating the costs of controls, attention is focused on boilers larger than 100 MMBtu/hr that are more likely to install control technology in order to comply with this rule.

The cost of NOx control includes capital cost and operating cost. The capital cost is a one-time cost that is amortized over a period of time. So, a portion of the capital cost is applied to each year of operation. The operating cost is experienced annually. In calculating the "cost effectiveness" of removing NOx, the annualized cost of the NOx control is divided by the tons of NOx reduced over that year. Because there is variability in the capital and operating cost from one facility to another and there is some variability in the effectiveness of control for a technology at one facility versus another, there is some variability to be expected in the cost numbers. Something else that affects cost effectiveness significantly is the baseline NOx level. The lower the baseline NOx level (NOx prior to adding controls), the higher the cost in $/ton of NOx reduced. So, if a technology is added to a facility without any NOx control, the cost in $/ton of removal will be less than for if the same technology were installed on a unit that is initially better controlled – even if the actual dollars spent are more. Also, capacity factor impacts cost effectiveness because the annual capital cost amortization does not change even if the system is not operated much. Therefore, if capacity factor is low, the cost in $/ton of NOx removed will be very high.

Because of all of these factors, the costs in $/ton shown in this report will be shown to vary widely in some cases. Since the proposed Illinois rule allows averaging at a source, it is reasonable to expect that facility owners will install technology on units where it will most likely be used – high capacity factor units. For this reason it is reasonable to assume that the expected costs for this rule would be near the lower end of the cost ranges shown.

Some of the sources cited in this section on control cost were dated several years ago, such as in the early 1990's. Although there has been some inflation in the overall economy in that time, costs for many of these technologies (in terms of $/ton of NOx removed) in nominal dollars have not changed dramatically because of competition and technical advances have kept prices relatively low, especially for combustion controls. In fact, the technical advances have also improved performance, which tends to benefit (reduce) the cost effectiveness (in $/ton of NOx removed) somewhat.

Tables 2-17a, b and c show a summary of control costs that have been compiled from various sources.

Cost effectiveness data has been compiled and compared from the following sources:

1. Alternative Control Techniques Document- NOx Emissions from Industrial/ Commercial/ Institutional (ICI) Boilers. March 1994. USEPA
2. AirControlNet, Version 4.1, Documentation Report, dated September 2005. USEPA
3. "Controlling Nitrogen Oxides under the Clean Air Act: A Menu of Options" dated July 1994. STAPPA/ALAPCO. (This document relies on federal ACT document and other sources for cost effectiveness figures)
4. Khan, S. *Methodology, Assumptions, and References Preliminary NOx Controls Cost Estimates for Industrial Boilers.* http://cascade.epa.gov/RightSite/dk_public_collection_item_detail.htm?ObjectType=dk_docket_item&cid=OAR-2003-0053-0170&ShowList=xreferences&Action=view (table is shown as Table III-4 in item 5 below) *Note that these estimates are preliminary developed from AirControl Net*
5. "Controlling Fine Particulate Matter under the Clean air Act: A Menu of Options" dated March 2006. STAPPA/ALAPCO
6. "Status Report on NOx Controls", prepared by Andover Technology Partners for the Northeast States for Coordinated Air Use Management (NESCAUM), December 2000. (denoted NESCAUM 2000 in this report)
7. Midwest Regional Planning Organization (RPO) "Petroleum Refinery Best Available Retrofit Technology (BART) Engineering Analysis Prepared for The Lake Michigan Air Directors Consortium (LADCO) Prepared by: MACTEC Federal Programs / MACTEC Engineering and Consulting, Inc. (denoted LADCO 2005)
8. Institute of Clean Air Companies (2006). "Selective Non-Catalytic Reduction Technology Costs for Industrial Sources." Letter from ICAC to OTC [Ozone Transport Commission].
9. Bill Neuffer, USEPA, http://www.epa.gov/air/ozonepollution/SIPToolkit/documents/stationary_nox_list.pdf

The Illinois EPA is relying on these documents to estimate the cost effectiveness of controlling NOx emissions from ICI boilers in Illinois affected by the Illinois NOx regulations proposed by this rulemaking.

2.4.1 ACT Cost Effectiveness

Three cost considerations are presented in the ACT document: total capital costs, total annual O & M costs, and cost effectiveness. The total capital cost is the sum of the purchased equipment costs, direct installation costs, indirect installation costs, and contingency costs. Annual costs consist of the direct operating costs of materials and labor for maintenance, operation, utilities, and material replacement and disposal and indirect operating charges including plant overhead, general administration, and capital recovery charges. The total capital investment was annualized using a 10-percent interest rate and an amortization period of 10 years. Cost effectiveness, in dollars/ton of NOx removed, is calculated for each control technique by dividing the total annual cost by the annual tons of NOx removed. The base year for the cost effectiveness is 1992. See Appendix A-1.

2.4.2 Cost Effectiveness Data from AirControlNet

AirControlNet is a software program from USEPA that is used to estimate control costs. The document details all the assumption used in calculating control cost effectiveness for various control technologies. For more information, please review the documentation report referenced above. Generally a discount rate of 7 percent and a capacity factor of 65 percent are assumed. Other assumptions include electricity cost of $0.05/kW-hr, coal cost of $1.60/million Btu and natural gas cost of $2.50/million Btu, equipment life of 15 years for combustion controls and 20 years for post-combustion controls, ammonia cost of $225/ton. All costs are in 1990 dollars. For more detailed information on assumptions, or any control specific variation in assumptions, please refer to the documentation report. AirControlNet also provides a model to calculate cost effectiveness data for any year up to 2004, but the data in the tables are for the year 1990.

2.4.3 Cost Effectiveness Data from STAPPA/ALAPCO document dated July 1994

The document provides a menu of options for controlling NOx emissions under the Clean Air Act. Cost effectiveness data is generally based on the ACT for ICI boilers. Other sources used for cost effectiveness data include California Air Resources Board, April 29, 1987 report and Santa Barbara County, December 1991 report. All costs are in 1993 dollar and are based on 60 percent boiler capacity. For more details, please read this STAPPA/ALAPCO document.

2.4.4 Cost Effectiveness Data from STAPPA/ALAPCO document dated March 2006

The document provides a menu of options for controlling fine particulate matter emissions under the Clean Air Act. Since NOx emissions are a precursor to fine particulate emissions, the report also summarizes capital cost of NOx controls and cost effectiveness data. All costs are in 2004 dollar. For more details, please read this STAPPA/ALAPCO document.

2.4.5 Cost Effectiveness Data from NESCAUM 2000 Report.

This document, which was prepared by Andover Technology Partners, provides several cases of ICI boilers that installed NOx control hardware. Some examples are provided in Table 2.11 and also in Table A-3 of the Appendices.

2.4.6 Cost Effectiveness from Khan 2003

See Appendix A-2. This document, prepared by Sikander Khan of USEPA, documents preliminary estimates of the cost of controlling NOx emissions on industrial boilers using AirControlNet. Based upon a telephone conversation with Mr. Khan, this document was actually developed to solicit comments at a time when USEPA was considering including industrial boilers as part of the Clean Air Interstate Rule (CAIR). USEPA later decided not to include ICI boilers in CAIR. So, the results of this study should be regarded as preliminary and are shown only because there is some consistency with many of the other studies that have final results. With regard to this study, there is probably greatest concern over the cost estimates of SCR because of limited data and because of price escalation that has been experienced in recent years with SCR. The results of calculations that are shown in Figure 2-17 were performed in an effort to address escalation in SCR costs experienced since the base year 1999$ of this analysis.

2.4.7 Cost Effectiveness Data from LADCO 2005

Tables 2-17a, b, and c include cost effectiveness of NOx controls for oil and gas fired boilers in the LADCO region that is taken from LADCO 2005. See Appendix A-4.

2.4.8. Cost Effectivenss of SNCR from ICAC

This refers to the data shown in Figure 2-14a.

2.4.9 Cost Effectiveness by Bill Neuffer of USEPA

Mr. Neuffer works for USEPA's Office of Air Quality Planning and Standards (OAQPS). He prepared a table of control technologies and cost effectiveness in 2006 as part of the SIP Tool Kit for states.

2.5 Cost Effectiveness of NOx Control for large EGU Boilers

All of the EGUs in the Chicago NAA and Metro-East NAA are currently subject to MPS or CPS requirements under 35 Ill. Adm. Code Part 225. Therefore, it is not envisioned that this rule will cause increased cost for facilities over existing requirements.

Table 2-17a: Cost Effectiveness Data for Natural Gas-Fired ICI Boilers

Type of Unit	Unit Capacity, mmBtu/hr	NOx Control Technology	Controlled NOx Level, lb/mmBtu	Data Source	Cost-Effectiveness, $/Ton NOx Removed
Natural Gas-fired Watertube Single Burner	150	FGR	0.05	Ref. 1	1390-1670
	150	SCR	0.024	Ref. 1	2060-2350
	100	SCR	80% Control	Ref. 4	1689-26859
	Small*	SCR	80% control	Ref. 4	2230-2860
	100	LNB/OFA/FGR	80% Control	Ref. 4	700-12374
	100	LNB+FGR	0.07	Ref. 1	1,110-3,090
	150	LNB+FGR	0.07	Ref. 1	990-2,730
	250	LNB+FGR	0.10	Ref. 1	650-1760
	150	WI	0.05	Ref. 1	N/A
	50	WI + OT	0.06	Ref. 1	710-820
	100	WI + OT	0.06	Ref. 1	570-650
	150	WI + OT	0.06	Ref. 1	540-610
	50	LNB	0.08	Ref. 1	570-2,390
	100	LNB	0.09	Ref. 1	410-1,670
	150	LNB	0.09	Ref. 1	360-1,450
	100	LNB+OFA	60% Control	Ref. 4	559-10521
Natural Gas-fired Watertube Field-Erected Multiple Burner	MBWT	SCR	0.024	Ref. 1	2060-2350
	250	SCR	80% Control	Ref. 4	1354-21095
	100	SCR	80% Control	Ref. 6	3100-6100
	350	SCR	80% Control	Ref. 6	2000-3600
	500	SCR	70-90%	Ref. 7	2444-7176
	1000	SCR	80% Control	Ref. 4	986-14815
	250	LNB/OFA/FGR	80% Control	Ref. 4	543-9415
	1000	LNB/OFA/FGR	80% Control	Ref. 4	368-6204
	250	BOOS+WI+OT	0.06	Ref. 1	530-570
	500	BOOS+WI+OT	0.08	Ref. 1	400-430
	100	BOOS+OT	0.09	Ref. 1	440-510
	150	FGR	50-65%	Ref. 2	1390-1670
	Large	SNCR	50%	Ref. 9	1600
	Large*	SNCR	50% control	Ref. 3	1570
	MBWT**	SNCR	0.10	Ref. 1	N/A
	250	BOOS+OT	0.12	Ref. 1	280-330
	250	LNB+OFA	60% Control	Ref. 4	424-7913
	1000	LNB+OFA	60% Control	Ref. 4	280-5260
	250	LNB	0.12	Ref. 1	3,030-6,210
	500	LNB	40% Control	Ref. 7	786-3841
	500	ULNB	75%-85%	Ref. 7	750-850
	500	LNB	0.15	Ref. 1	1,920-3,900
	500	LNB+FGR	50-70%	Ref. 7	981-3994
	500	LNB+SNCR	50-89%	Ref. 7	1560-3688
	500	ULNB+SCR	85-97%	Ref. 7	2925-5836

* Small means less than 1 ton/day NOx, Large means greater than 1 ton/day NOx

**MBWT means Multiple Burner Watertube

Table 2-17b: Cost Effectiveness Data for Fuel Oil-Fired ICI Boilers

Type of Unit	Unit Capacity, mmBtu/hr	NOx Control Technology	Controlled NOx Level, lb/mmBtu	Data Source	Cost-Effectiveness, $/Ton NOx Removed
Distillate Oil Watertube Single Burner	50	SCR	0.03	Ref. 1	1,500-1,900
	50	SCR	0.03	Ref. 1	2070-2360
	150	SCR	0.03	Ref. 1	1560-1780
	100	LNB	0.10	Ref. 1	370-1,500
	150	LNB	0.10	Ref. 1	600-750
	50	LNB+FGR	0.07	Ref. 1	2,100-4,700
	100	LNB+FGR	0.08	Ref. 1	800-2,580
	250	LNB+FGR	0.08	Ref. 1	580-1,910
	Small*	LNB+FGR	60% control	Ref. 3	1090-2490
	Small*	SCR	80% control	Ref. 3	2780
Distillate Oil Watertube Field-Erected Multiple Burner	150	LNB	45% control	Ref. 2	600-750
	150	SCR	80-90% control	Ref. 2	1560-1780
	150	SNCR	30-70% control	Ref. 2	2450-3060
	250	LNB	0.10	Ref. 1	3,630-7,450
	500	LNB	0.10	Ref. 1	2,880-5,850
Residual Oil Watertube Single Burner	50	SCR	0.06	Ref. 1	2,030-2,900
	100	SCR	0.06	Ref. 1	1,440-2,530
	250	SCR	0.06	Ref. 1	1,140-2,190
	150	SCR	0.06	Ref. 1	1,290-1,480
	Small*	SCR	80% control	Ref. 3	1480-1910
	100	SCR	80% control	Ref. 4	1245-1694
	50	LNB	0.19	Ref. 1	240-1,010
	100	LNB	0.19	Ref. 1	190-790
	250	LNB	0.19	Ref. 1	150-580
Residual Oil Watertube Field-Erected Multiple Burner	MBWT	SCR	0.045	Ref. 1	1,140-2,190
	150	SCR	0.045	Ref. 1	1,290-1,480
	Small*	SCR	80% control	Ref. 3	1480-1910
	250	SCR	80% control	Ref. 4	997-1343
	350	SCR	80% control	Ref. 5	1000-3000
	1000	SCR	80% control	Ref. 4	760-1,017
	Large*	SNCR	50% control	Ref. 3	1050
	250	LNB	0.19	Ref. 1	1,910-3,920
	350	LNB	50%	Ref. 6	1576-2977
	350	burner mod	25%	Ref. 6	189-357
	350	Rotamix	~75%	Sec 2.3.6	~1,000
	500	LNB	0.19	Ref. 1	1,520-3,080
	750	LNB	0.19	Ref. 1	1,330-2,680
	150	LNB	45% control	Ref. 2	490-610

* Small means less than 1 ton/day NOx, Large means greater than 1 ton/day NOx
MBWT means multiple burner watertube

Table 2-17c: Cost Effectiveness Data for Coal and Wood-Fired ICI Boilers

Type of Unit	Unit Capacity, mmBtu/hr	NOx Control Technology	Controlled NOx Level, lb/mmBtu	Data Source	Cost-Effectiveness $/Ton NOx Removed
Pulverized Coal Wall-Fired Boiler	100	SCR	80% control***	Ref. 4	1349-7262
	250	SCR	80% control***	Ref. 4	1123-5924
	1000	SCR	80% control***	Ref. 4	876-4481
	250 - 750	SCR	0.14	Ref. 1	3,000 – 4,800
	Large**	SCR	70% control	Ref. 3	1,070
	Small**	SCR	70% control	Ref. 3	1,260
	350	SCR	80%+	Ref. 5	2000-3000
	350	SCR	80%+	Ref. 6	1300-3000
	500	SCR	80-90% control	Ref. 2	1,790-2,030
	350	SCR	90%	Fig 2-17	$1500-$3500
	350	SNCR	35%	Ref. 6	1300-1814
	~800	ROTAMIX	70-83%	Sect. 2.3.6	~$675
	400	LNB	0.35	Ref. 1	1,170 – 1,530
	250	LNB	51% control	Ref. 4	389-2305
	350	LNB	36%	Ref. 6.	730-1378
	100	LNB+OFA	51-65% control*	Ref. 4	593-757
	250	LNB+OFA	51-65% control*	Ref. 4	454-581
	1000	LNB+OFA	51-65% control*	Ref. 4	306-392
Coal-CFBC	250 - 750	SNCR-Urea	0.08	Ref. 1	810 – 1,130
	Large**	SNCR-Urea	40% control	Ref. 3	670
	Small**	SNCR-Urea	75% control	Ref. 3	900
	N/A	SNCR-NH3	0.04-0.09	Ref. 1	N/A
	N/A	SNCR	76-80%	Ref. 5	N/A
	N/A	SNCR	40%-75%	Ref. 9	700-900
	N/A	SCR	0.12	Ref. 1	N/A
	N/A	SCA+FGR	0.14	Ref. 1	N/A
Coal-BFBC	N/A	SNCR-NH3	0.04-0.09	Ref. 1	N/A
	N/A	SNCR-Urea	0.03-0.14	Ref. 1	N/A
	N/A	SCA	0.10-0.14	Ref. 1	N/A
Coal-Spreader Stoker	250 - 750	SNCR-Urea	0.22	Ref. 1	1,280 – 1,440
	N/A	SNCR-NH3	0.15-0.18	Ref. 1	N/A
	N/A	SNCR	57%-80%	Ref. 5	N/A
		SNCR	40	Ref. 9	700-900
	Small**	SNCR	40% control	Ref. 3	873-1015
	N/A	Gas Co-firing	0.18-0.20	Ref. 1	N/A
Coal-Stoker	500	SNCR	30-70% control	Ref. 2	940-1,170
Wood Stoker	150	SNCR	0.11	Ref. 1	1,270-2,380
	N/A	SNCR	46%-75%	Ref. 5	N/A
	250	SNCR	0.11	Ref. 1	1,080-2,130
	500	SNCR	0.11	Ref. 1	890-1,870
Solid Fuel	>100	SNCR	50%+	Ref. 8	1500-2500

* For Bituminous and Sub-Bituminous Coals, control efficiencies are 51% and 65%, respectively. Cost data is for 83% capacity factor

** Small means less than 1 ton/day NOx, Large means greater than 1 ton/day NOx

*** 80% control corresponds to 0.14 lb/mmBtu NOx for wall-fired boilers and 0.12 lb/mmBtu for tangential- fired boilers

3. Process Heaters

3.1 Introduction and Summary of this Section

This section provides a description of the process heater source category, the mechanism of NOx formation, the technical feasibility of controls, the cost effectiveness of controls, the existing and proposed regulations and the sources affected by the regulations.

Most process heaters burn natural gas, refinery fuel gas, or distillate fuel oil which are low in fuel nitrogen. Baseline emissions from process heaters burning natural gas, refinery fuel gas and distillate fuel are inherently low because of low fuel nitrogen contents. These process heaters can be controlled by a number of combustion modification techniques including low NOx burners (LNB), ultra low NOx burners (ULNB) and flue gas recirculation (FGR), which are often less expensive than post combustion techniques such as selective catalytic reduction (SCR) and non-selective catalytic reduction (SNCR). In most cases NOx emissions can be reduced to the target level by combustion modification only, but in some cases it may be necessary to install a combination of combustion control and post-combustion control technologies.

Some heaters burn residual fuel oil and or refinery pitch which are high in fuel nitrogen. Depending on the nitrogen content of the fuel oil and process heater design, baseline NOx emissions could vary substantially. To economically control NOx emissions from such process heaters, it may be necessary to use fuel which is low in fuel nitrogen and choose combustion conditions that generate lower amount of NOx during combustion. Controlling NOx emissions from such process heaters may involve the use of a combination of combustion and post combustion controls. Switching to distillate fuel oil may be another option.

The proposed regulations target those process heaters which are located in the Chicago NAA and Metro-East NAA that are located at a major source of NOx emissions. A major source is a source that emits or has the potential to emit 100 tons or more of NOx per year. Process heaters that are greater than100 million Btu/hour capacities are subject to numerical emission limits shown in Table 3-1. Process heaters that are equal to or less than 100 million Btu/hour with annual NOx ≥15 tons per year and ozone season NOx ≥5 tons are required to do combustion tuning (CT) annually. Combustion tuning is expected to reduce NOx emissions from 5 to 25 percent.

Table 3-1. Emissions Limits for Process Heaters larger than 100 MMBtu/hr

Fuel	Type	NOx limit (lb/MMBtu)
Gaseous Fuels	All	0.07
Residual Fuel Oil	Natural Draft	0.10
Residual Fuel Oil	Mechanical Draft	0.15
Other Liquid Fuels	Natural Draft	0.05
Other Liquid Fuels	Mechanical Draft	0.08

3.2 Process Description and Sources of Emissions

3.2.1 Process Heater Description

Process heaters are mainly used in petroleum processing and petrochemical industries. Some process heaters are used in chemical manufacturing, gas processing, and other industries. Process heaters are also known as process furnaces and direct-fired heaters. There is a broad spectrum of process heater designs and capacities. They are used where boilers or steam heaters are not appropriate. Process heaters are used for heating fluids other than water.

The fluid may be heated either to raise temperature of the feed before additional processing or to initiate a chemical reaction within the tubes. The first category of heaters is called feed heater. Examples of feed heaters include preheaters and reboilers for distillation columns, hot oil furnaces, preheaters for catalytic cracking and hydroprocessing etc. They are found both in petroleum refining and chemical manufacturing industries. The second category is called reaction feed heater. Some examples of reaction feed heaters include steam-hydrocarbon reformers used in ammonia and methanol manufacturing, pyrolysis furnaces used in ethylene manufacturing, and thermal cracking used in refining operations.

Regardless of the heater type, combustion air is supplied to the burners in one of two ways: via natural draft (ND) or mechanical draft (MD) systems. Natural draft heaters rely on flame buoyancy to motivate the combustion air, usually introduced at ambient conditions, to the up-flow burners. Mechanical draft heaters use fan(s) to motivate combustion air. Most process heaters are natural-draft, vertical-flow, atmospheric combustion systems. Most natural-draft process heaters have multiple burners under 10 MMBtu/hr each. But, some burners can be somewhat larger or smaller. Figures 3.1 and 3.2 illustrate two common types of natural draft process heaters – a natural draft cabin process heater and natural draft box process heater. Other types are used as well.

The larger process heaters may have air preheaters, which will require a mechanical draft system to overcome the pressure drop of the air preheater.

Burner selection depends on several factors including process heat requirements, fuel type, and draft type. Natural draft gas-fired burners may be simpler in operation and design than oil-fired burners and are classified either as premix or raw gas burners. In premix burners, about 50 to 60 percent of the air necessary for combustion is mixed with the gas prior to combustion at the burner tip. This air is induced into the gas stream as the gas expands through the orifices in the burner. The remainder of the gas is provided at the burner tip. Raw gas burners receive fuel gas without any premixed combustion air with diffusion of air and fuel at the flame.

Oil-fired burners are classified according to the method of atomization. Atomization is needed to increase the mixing of fuel and combustion air. Three types of atomization commonly used are mechanical, air, and steam.

Combination burners can burn 100 percent oil, 100 percent gas, or any combination of oil and gas. A burner with this capability generally has a single oil nozzle in the center of a group of gas nozzles.

The number of burners in a process heater can range from 1 to over 100. In a petroleum refinery, the average number of burners is estimated at 24 in ND heaters with average heat input capacity of about 70 million Btu/hour. The average number of burners is estimated at 20 in MD heaters with ambient combustion air and average heat input for the heaters of 104 million Btu/hour. In other words, burners in process heaters are typically well below 10 million Btu/hr even for larger heaters - much smaller in size than burners used in boilers of similar heat input. The reason is because even heat distribution is essential in fired heaters to avoid damaging the product being heated.

Figure 3-1. End and Bottom Views of a Natural-Draft Cabin Process Heater

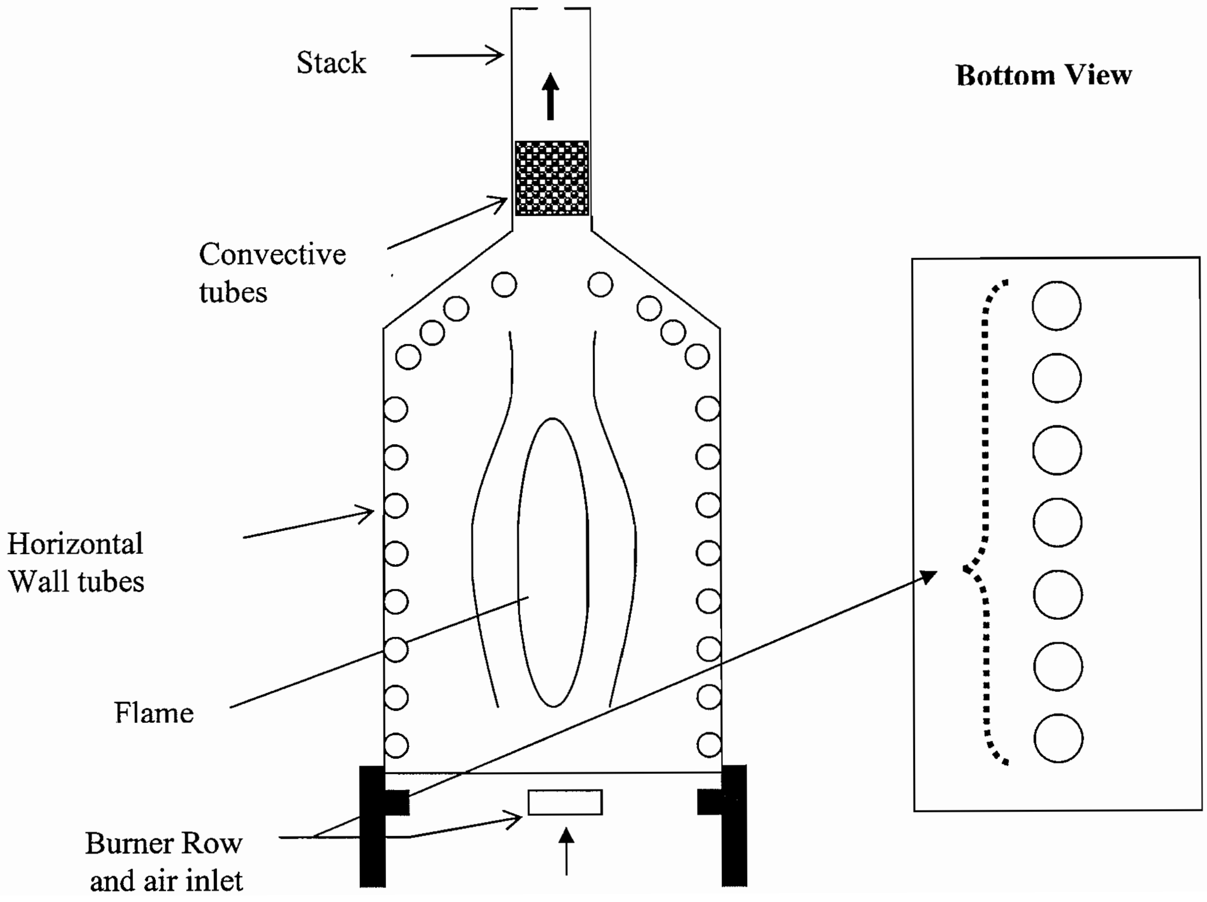
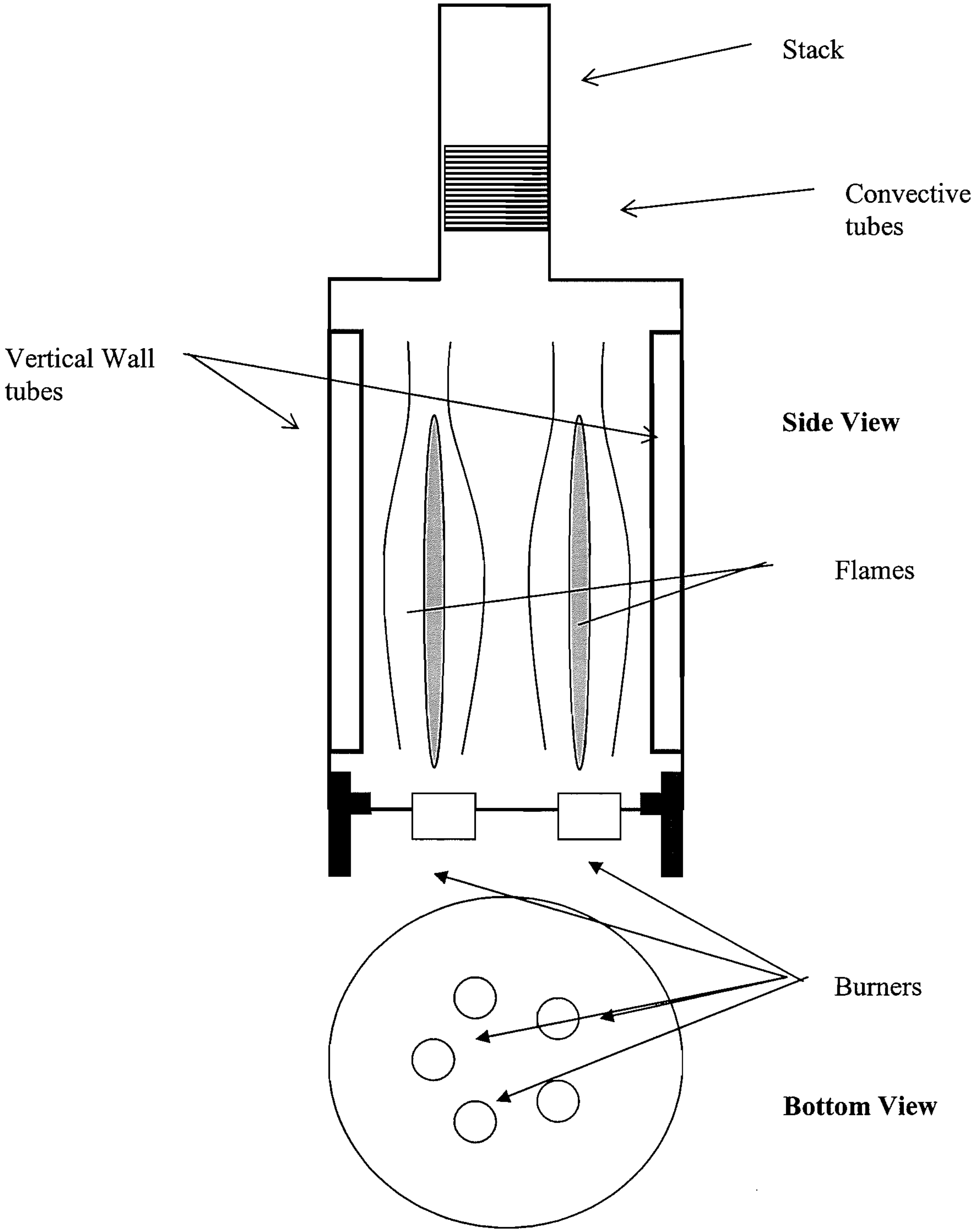


Figure 3-2. Natural Draft Cylindrical Process Heater



3.2.2 Factors Affecting Uncontrolled NOx Emissions

There are several factors which affect baseline or uncontrolled NOx emissions from process heaters. These include heater design parameters such as burner design, fuel type, combustion air preheat, firebox temperature, and draft type, and heater operating parameters such as excess air, burner flame characterization etc. Since these factors influence each others, uncontrolled emissions could vary over a wide range. This section discusses how boiler design, fuel characteristics, and boiler operating characteristics, can influence baseline (uncontrolled) NOx emissions.

3.2.2.1 Heater Design Parameters

There are several heater designs used in industry depending upon the type of fuel burned. The heater design parameters that affect the level of NOx emissions include fuel type, burner type, combustion air preheat, firebox temperature and draft type.

3.2.2.2 Fuel Type

Process heaters burn a variety of gaseous and liquid fuels including natural gas, refinery fuel gas, hydrogen, butane, pentane, distillate fuels oils and residual fuel oils. In addition, some process heaters burn refinery pitch. Research shows that combustion of distillate fuel oils generates more NOx emissions than natural gas under identical operating conditions. Refinery fuel gas (RFG) usually has trace amounts of HCN, NH_3, and other nitrogen bearing species that may be oxidized to NOx, but usually RFG does not contain fuel bound nitrogen. Therefore combustion of RFG generates somewhat higher NOx emissions as compared to natural gas. Fuel NOx could be a significant portion of total NOx when high nitrogen fuels such as residual oil are combusted.

Hydrogen content of refinery gas which is burned in low- and medium-temperature process heaters can vary from 0 to 50 percent. The heating value of such fuels varies from 700 to 2200 Btu/scf depending on hydrogen content. Hydrogen content of refinery gas which is burned in high-temperature process heaters such as pyrolysis furnaces can be as high as 80 percent. The heating value of such high hydrogen fuels varies from 400 to 600 Btu/scf depending on hydrogen content. This variation in fuel hydrogen content causes changes in flame temperature, propagation, and flame volume. High hydrogen fuels produce hotter flames and hence higher levels of thermal NOx.

3.2.2.3 Burner Type

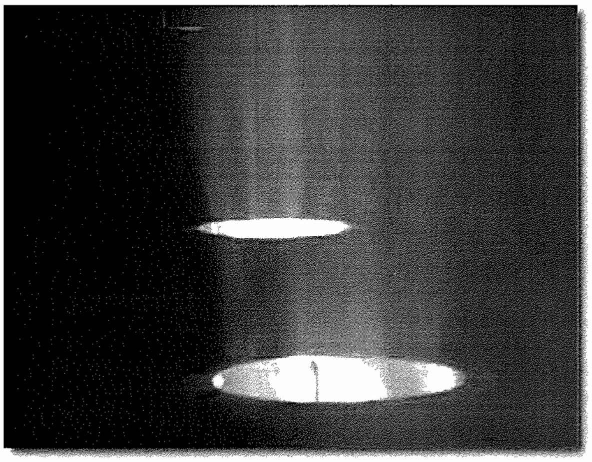
Burners use one of two methods for mixing the fuel and air – diffusion or premixing. Diffusion flame burners – which rely on mixing of fuel and air in the flame zone - were more common in the past. They tend to have better flame stability and turndown. Natural draft diffusion flame burners may be called raw-gas burners. Premixed burners premix fuel and air prior to ignition. Premixed burners – when operated as lean-premixed - can have a significant advantage for NOx control in some cases, but they tend to produce a less stable flame than diffusion-flame burners because the burner stoichiometry of lean-premixed burners must be more carefully controlled.

Turndown has been improved in recent years through the use of variable geometry on some burners using lean-premixed combustion.

Diffusion-flame burners generally rely on air staging for NOx control, and to a much lower extent, fuel staging. Air staging is performed by initially having the fuel and air burn in a fuel rich zone, where no NOx is formed, and then air is added to burn out the fuel in a controlled manner to minimize NOx formation. In fuel staging the fuel is added in two stages. The first combustion zone is lower intensity than if fuel were added in one stage, which helps reduce NOx formation. The latter stage acts as a "reburn" zone – reducing NOx from the first stage somewhat.

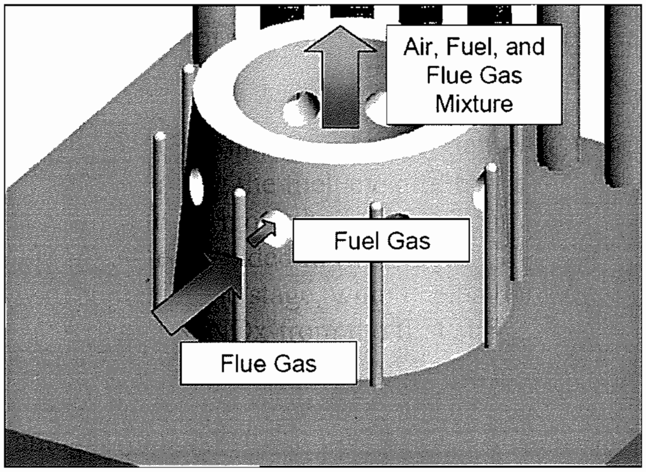
In addition to better flame stability, another advantage of diffusion-flame burners is that they can use internal flue gas recirculation (FGR), which enables NOx reduction with FGR without the need for external ductwork and fans. Figure 3-3a is a photo of the flames from Callidus Ultra Blue Burners, which uses internal FGR and have been shown to achieve under 10 ppm NOx in some applications, and 10-20 ppm in typical applications.

Figure 3-3a. Callidus Ultra Blue Burner
http://www.callidus.com/pages/next_gen.htm



Premixed burners offer the potential for lower NOx emissions when using low nitrogen fuels because premixed burners can employ lean-premixed combustion (LPC) for lower NOx. It is also possible to use fuel staging with an LPC burner. However, to practice FGR with an LPC burner requires external ductwork and fans, which may significantly increase the cost.

Figure 3-3b. Internal FGR for Callidus Ultra Blue Burner[24]



Some newer burners use a porous surface of ceramic or metallic fibers to burn gas fuels. They can only be used in a mechanical draft configuration. These burners are premix burners and combustion occurs on the outer surface of radiant burners. Combustion occurs at relatively low temperature (1830°F) with a stable flame. These burners produce low NOx as well CO and HC emissions.

Oil-fired burners are diffusion burners and typically use air staging for NOx control.

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[24] Heat Input Affects NOx Emissions from Internal Flue Gas Re-Circulation Burners; http://texasiof.ces.utexas.edu/texasshowcase/pdfs/presentations/c1/dbishop.pdf

There are differences in performance from one heater to another due to differences in heat transfer and other effects. The heat transfer in these heaters must be carefully controlled because improper heat transfer may result in undesirable coking reactions. So, a burner may not be able to operate at its optimum combustion point, but rather under a combustion condition that works well with the needs of the fired heater and also provides a stable flame. Although the burners are normally tested at the manufacturer's test facility in advance of installation, there is occasionally some difference in performance from what will occur when installed in the actual heater, especially with regard to NOx emissions. Therefore, there is some uncertainty about how the burners will perform in place on a day-to-day basis as compared to what is shown in testing at the manufacturer's laboratory.

Another complication is that these burners will often operate on variable fuels. Refineries prefer to burn gas in the fired heaters that would otherwise be flared off. Natural gas is mostly used to supplement the fuel that is generated on site. Therefore, the fuel may vary from gas that is mostly hydrogen, to light hydrocarbons, to natural gas. This makes it more difficult to control a burner to the very tight combustion conditions necessary for single-digit NOx emissions and low CO emissions.

Natural draft burners generally are in the size range of 6-12 MMBtu/hr, with about 8-10 MMBtu/hr being most typical. The price for a burner may be in the range of the following: [25]

4 MMBTU/hr burner: about $5,000
8 MMBTU/hr burner: about $8,000

or, roughly, $1,000/MMBTU

This is just the burner cost. The total cost of the installed equipment is often several times the cost of the burner. Frequently, the fuel system will require some modification because the new burners tend to have finer orifices that can plug without fuel system improvements and the heater floor will often require modification or even replacement. Other equipment additions may be necessary as well. The estimated cost of the entire project could be two to five times the price of the burner itself, sometimes more, resulting in a cost of about $2,000-$5,000/MMBTU. However, unlike the burners used on boilers, the burners used on natural draft fired heaters normally do not require external flue gas recirculation. External FGR would add significant cost due to the additional ductwork and fan.

3.2.2.4 Combustion Air Preheat

Combustion air preheat is an efficient way to save fuel in mechanical draft heaters, but preheating of air increases the flame temperature and hence higher amounts of NOx are produced. In mechanical draft process heaters, use of combustion air preheat can increase NOx emissions by as much as 40% when air preheated to 400°F is used. Combustion air preheat is not used in natural draft fired heaters.

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[25] http://www.andovertechnology.com/HGA_Market_Report_secure.pdf

3.2.2.5 Firebox Temperature

Firebox temperature is directly related to flame temperature. Higher firebox temperature will produce more thermal NOx. In processes requiring high firebox temperatures, such as steam hydrocarbon reformers and olefins pyrolysis furnaces, higher thermal NOx is produced as compared to low- and medium-firebox furnaces. Research shows that increasing firebox temperature from 1300°F to1900°F increases thermal NOx formation by about 50 percent for gas-fired furnaces. Oil-fired furnaces are less sensitive to firebox temperature increase because fuel NOx is less sensitive to temperature than thermal NOx.

3.2.2.6 Draft Type

Two basic methods for combustion air supply are natural draft (ND) and mechanical draft (MD). MD systems can be further subdivided into forced draft, induced draft, and balanced draft. These three types are distinguished by the location of the fan relative to the heating unit. In forced draft, a fan is located upstream of the firebox, in induced draft, a fan is located downstream of the heating unit, and in balanced draft, both forced as well as induced draft fans are used. Balanced draft is more common with boilers than with process heaters. In ND heaters, the pressure difference between the hot gases in the stack and the cooler outside air results in a draft which causes cool combustion air to flow into the burners.

Draft type can influence NOx emissions by affecting the excess air in the combustion zone. By converting a ND heater to MD heater and lowering the excess air, NOx emissions can be reduced.

3.2.2.7 Heater Operating Parameters

Some of the operating parameters that affect NOx emissions from process heaters include excess air and burner adjustments. Excess air is needed to ensure complete combustion of fuel in the burner. A typical excess air level for a process heater is approximately 15 percent. Excess air present, of course, will depend on fuel type, draft type, and burner design.

Research has shown that for every 1 percent increase in excess oxygen level, NOx emissions increase from 6 to 9 percent. Beyond about 6 percent excess oxygen in the flue gas, NOx formation begins to decrease because of the flame cooling effect. Radiant burners are reported to be capable of minimizing NOx emissions without sacrificing fuel efficiency, even with excess air levels of 10 to 20 percent.

Burner adjustments can affect NOx emissions by altering the flame characteristics. By increasing flame length, the peak flame temperature can be reduced which will affect NOx emissions. On the other hand, if a flame is compact, it will produce high intensity flame, and hence higher levels of NOx emissions. The flame length in multi-stage burners can be changed by changing relative amounts of primary and secondary airs, but such adjustments may not coincide with optimum NOx control.

3.3 Baseline or Uncontrolled NOx Emissions

Baseline NOx emissions are strongly influenced by heater design, type of fuel burned, peak flame temperature, and oxygen concentration. Uncontrolled NOx emission factors (for units not equipped with low NOx technology) are listed in USEPA's Compilation of Air Pollutant Emission Factors: AP-42 and American Petroleum Institute (API) publications. The NOx emission factors predicted by these publications vary a lot and hence the approach adopted by the ACT document is to use the model heater approach in order to compare the uncontrolled NOx emissions from different types of heaters. The same approach has been used for comparing NOx control techniques.

The uncontrolled NOx emission factors for natural gas-fired, low and medium-temperature model heaters are 0.098 and 0.197 lb/mmBtu for natural draft (ND) and mechanical draft (MD) heaters, respectively. The uncontrolled NOx emission factors for the ND oil-fired model heaters are 0.20 and 0.42 lb/mmBtu for distillate and residual fuel-oil firing, respectively. The distillate and residual oil-fired MD heaters have uncontrolled NOx emission factors of 0.32 and 0.54, respectively. The uncontrolled emissions factors for the pyrolysis model heaters 0.135 and 0.162 lb/mmBtu for the natural gas and high-hydrogen fuel gas-fired heaters, respectively.

MD heaters generate more NOx emissions as compared to ND heaters because MD heaters use combustion air preheat which increases thermal NOx. Oil-fired heaters have higher baseline NOx emissions because they operate at higher temperature and hence generate more thermal NOx as compared to gas-fired heaters. Residual oil contains more fuel nitrogen as compared to distillate fuel oil, and combustion of residual fuel oil generates more fuel NOx as compared to distillate oil.

The Table 3-2 below gives provides baseline NOx emissions from model process heaters equipped with conventional (not low NOx) burners.

Table 3-2: Model Heaters: Uncontrolled NOx Emission Factors

	Uncontrolled Emission Factor		
Model Heater Type	Thermal NOx	Fuel NOx	Total NOx[a]
ND, Natural Gas-Fired[b]	0.098	N/A	0.098
MD, Natural Gas-Fired[b]	0.197	N/A	0.197
ND, Distillate Oil-Fired	0.140	0.06	0.200
ND, Residual Oil-Fired	0.140	0.28	0.420
MD Distillate Oil-Fired	0.260	0.06	0.320
MD, Residual Oil-Fired	0.260	0.28	0.540
ND, Pyrolysis, Natural Gas-Fired	0.135	N/A	0.135
ND, Pyrolysis, High Hydrogen Fuel Gas-Fired[c]	0.162[d]	N/A	0.162

[a] Total NOx = Thermal NOx + Fuel NOx

[b] Heaters firing refinery fuel gas with up to 50 mole percent hydrogen can have up to 20% higher NOx emissions than smaller heater firing natural gas

[c] High hydrogen fuel gas is fuel gas with 50 mole percent or greater hydrogen content

[d] Calculated assuming 50 mole percent hydrogen

N/A = Not applicable

3.4 Technical Feasibility of NOx Control

The control of NOx emissions from process heaters can be accomplished either through combustion modification controls, flue gas treatment controls, or a combination of these technologies. Combustion modification controls include low NOx burners (LNB) and ultra low NOx burners (ULNB). Post-combustion controls include selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR). Combination controls include low NOx burners with flue gas recirculation (FGR), SNCR, and SCR.

3.4.1 Combustion Controls

Combustion controls such as LEA, LNB, ULNB, and FGR inhibit NOx formation by controlling the combustion process. Low excess air (LEA) firing is the most effective process heater improvement techniques one can apply without incurring a capital cost. Low excess air lowers peak flame temperature and produces less oxidizing conditions, thus limiting thermal and fuel NOx. Many process heaters already minimize excess air levels to increase heater efficiency and decrease fuel requirement. Excess air levels can be reduced on almost all heaters, but this approach is most effective on mechanical draft heaters. Very low excess air levels may result in flame stability, as well as formation of soot and increased emissions of CO and hydrocarbons. A reducing atmosphere in the heater may also lead to corrosion of heat transfer surfaces. Lowering of excess air can reduce NOx emissions by 5 to 20 percent.

Combustion tuning incorporates low excess air and inspection of the process heater for proper working conditions.

Process Heater Tune-Up: Both natural-draft as well as mechanical draft process heaters can be made to operate with low excess air, but mechanical draft heaters are more amenable to low excess air firing.

The tune-up procedure as recommended by the process heater manufacturer should be followed, wherever possible. If the manufacturer procedure does not involve the use of CO and O_2 monitoring during combustion tuning, procedures as described in http://www.valleyair.org/rules/currntrules/r4304.pdf may be followed.

Prior to combustion tuning, inspection of all heat transfer surfaces, fuel systems, electric and combustion control systems, valves, refractories, fan housing, blades etc. should be checked, and repairs must be made, as needed.

LNB and ULNB: LNBand ULNB use staging techniques to reduce oxygen in the flame zone or supply excess air to cool the combustion process. Staged air LNB creates a fuel-rich primary combustion zone and fuel-lean secondary combustion zone. Staged fuel LNB creates a fuel-lean fuel-rich primary combustion zone and fuel-rich secondary combustion zone. ULNB uses a combination of internal FGR and staged-fuel LNB and hence provide lowest emissions amongst all low NOx burners as shown in Figure 3-4, and Figure 3-5 shows emissions levels for John Zink burners. Table 3-3 provides typical NOx reductions for different low NOx burners taken from the ACT document. As shown in the figures as well as Table 3-2, very high NOx reductions are achievable with low NOx burners (air or fuel gas staging) using FGR.

Table 3-3: NOx Reduction Potential for Different Low NOx Burners

Low NOx Burner Type	Typical NOx Reduction, %
Staged-air Burner	25-35
Staged-fuel Burner	40-50
Low-Excess Air Burner	20-25
Burner with External FGR	50-60
Burner with Internal FGR	40-50
Air or Fuel-gas Staging with Internal FGR	55-75*
Air or Fuel-gas Staging with External FGR	60-80

* Reductions of up to 90% have been demonstrated
Reference: Nitrogen oxides emissions reduction technologies in the petrochemical and refining industries. Charles E. Baukal et. al. Environmental Progress, Vol. 23, No. 1, April 2004.

John Zink is not the only supplier of burners with very low NOx emissions. Callidus, Maxum, Coen, Hamworthy and other companies also offer burner technology that is capable of providing very low emissions.

Ultra low NOx emissions require low excess oxygen levels and good control of fuel and air. Retrofit of low NOx burners normally also requires new controls possibly with additional instrumentation as shown in Figure 3-6. Figure 3-6 shows the use of a CO analyzer, oxygen analyzer and control of exit duct and inlet registers on a natural draft process heater.

Regulations in the Houston/Galveston Area required large process heaters (over 100 MMBtu/hr) to emit less than 0.025 lb/MMBtu. As a result, companies have retrofit many existing process heaters with low-NOx burners, allowing existing units to achieve NOx emissions rates in the range of 0.015–0.025 lb/MMBtu. New process heaters are capable of NOx emissions rates in the range of 0.010–0.015 lb/MMBtu.[5]

Figure 3-4: Comparison of an ultra low NOx burner (ULNB) with other burners (www.johnzink.com)

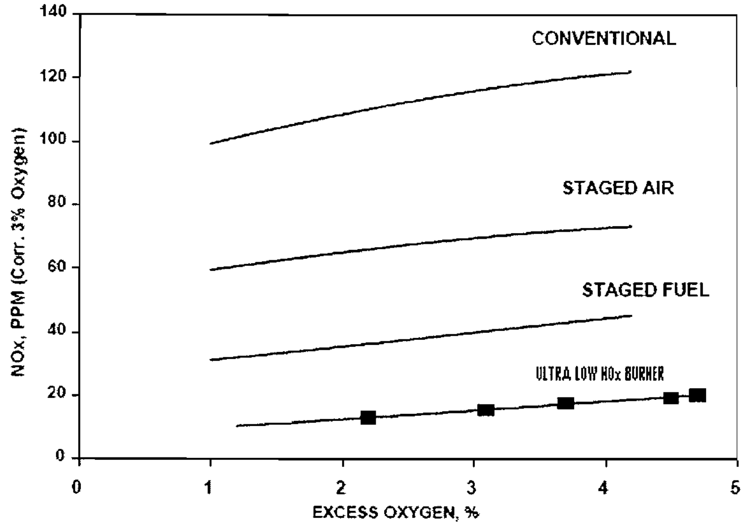


Figure 3-5. Representative emissions for three different John Zink company burners. SFG - using fuel staging, QMR - using internal FGR; and LM 300 – which is a lean-premixed burner with multiple combustion zones (www.johnzink.com)

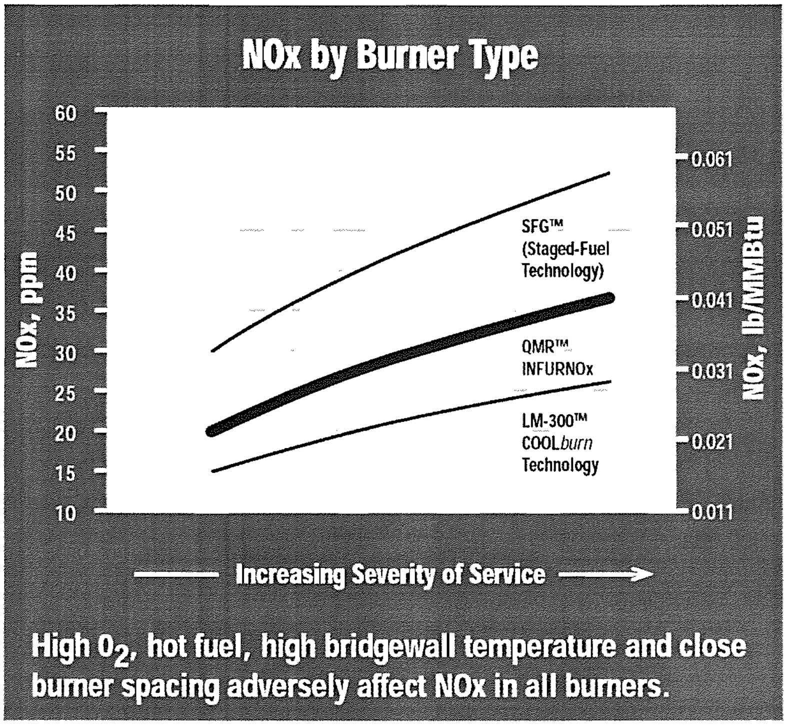
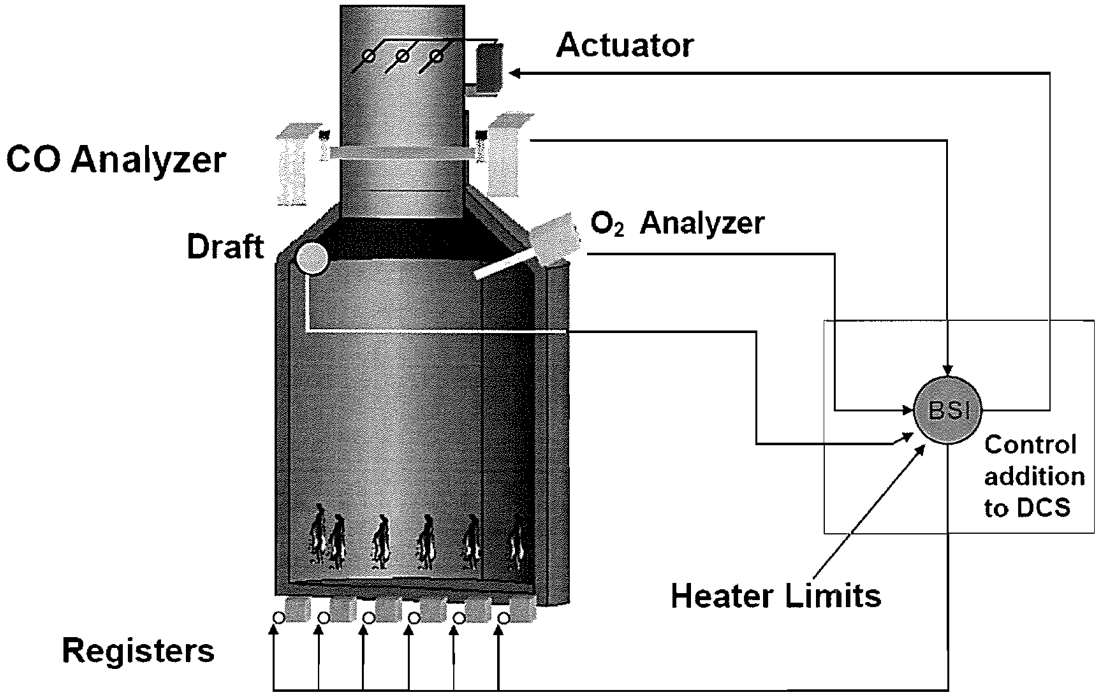


Figure 3-6 Low NOx burner controls on a natural draft process heater
www.perf.org/ppt/Bishop.ppt



3.4.2 Post-Combustion Controls

Unlike combustion controls, SNCR and SCR do not inhibit NOx formation, but reduce NOx in the flue gas. These techniques control NOx by using a reactant that reduces NOx to nitrogen (N_2) and water. The reactant, ammonia or urea for SNCR and ammonia for SCR, is injected into the flue gas stream. The effectiveness of the reactant depends on residence time and temperature. The optimum temperature window for SNCR effectiveness is about 1600° to 2000°F for ammonia based and 1650° to 2100°F for urea based SNCR. At temperatures above 2000°F, ammonia injection becomes counter productive, resulting in additional NO formation. Below 1600°F, the reaction rate drops and undesired amounts of ammonia are carried out in the flue gas. NESCAUM's 2000 study (See figure 2-11b of this report) showed data on eight refinery heaters equipped with ammonia SNCR that achieved 43% and 70% NOx reduction.

There are several types of SCR catalysts available in the market. These catalysts facilitate the reaction of ammonia with NOx in the flue gas. The optimum temperature window for SCR effectiveness using ammonia is 500-900°F.

It should be noted that SCR would require the conversion of a natural draft heater into mechanical draft. Natural draft-to-MD conversion does not in and of itself reduce NOx emissions. However, ND to MD conversion makes it possible to take advantage of thermal efficiency gains possible from adding an air preheater. In general studies such as this one, this efficiency improvement is not factored into the economics of an SCR retrofit, although for a specific application an owner probably would.

Tables 3-4 and 3-5 provide NOx reduction potential for control technologies for various types of process heaters taken from the 1993 USEPA Alternative Control Techniques Document- NOx Emissions from Process Heaters (Revised), EPA-453/R-93-034. Unfortunately, USEPA has not updated this document since 1993. ***As indicated in section 3.4.1 of this document, current state-of-the-art combustion controls are much better than shown in Tables 3-3 and 3-4 as a result of substantial advancements in combustion controls since 1993.*** As an example, Table 3-6 shows the state-of-the-art emissions rates per New Jersey's State of the Art (SOTA) Manual for Boilers and Process Heaters that was revised in 2004. As shown in the comparison of the NJ SOTA Manual in 2004 to the 1993 ACT document, the emissions levels possible for burners have improved dramatically in ten years due to the advancements in combustion controls.

Table 3-4: Model Heaters: Control Technique Effectiveness for Natural Gas- and Refinery Fuel Gas-fired Process Heaters from 1993 ACT

Process Heater Type	Control Technique	Total Effective NOx Reduction, %
Low and Medium Temperature Heater Natural Gas-Fired or Refinery Fuel Gas-Fired	LNB	50
	ULNB	75
	SNCR	60
	SCR	75
	LNB+FGR	55
	LNB+SNCR	80
	LNB+SCR	88
Pyrolysis Furnace Natural. Gas-Fired or Refinery Fuel Gas-Fired	LNB	25
	ULNB	50
	SNCR	60
	SCR	75
	LNB+FGR	55
	LNB+SNCR	70
	LNB+SCR	81

Reference: Alternative Control Techniques Document- NOx Emissions from Process Heaters (Revised), EPA-453/R-93-034, Table 2-2.

Table 3-5: Model Heaters: NOx Control Efficiencies for Distillate and Residual oil-Fired Process Heaters

Process Heater Type	Control Technique	Total Effective NOx Reduction, %	Controlled NOx, lb/mmBtu
Natural Draft, Distillate Oil	(ND) LNB	40	0.12
	(MD) LNB	43	0.18
	(ND) ULNB	76	0.05
	(MD) ULNB	74	0.08
	SNCR	60	0.08
	(MD) SCR	75	0.08
	(MD) LNB+FGR	43	0.18
	(ND) LNB+SNCR	76	0.05
	(MD) LNB+SNCR	77	0.07
	(MD) LNB+SCR	86	0.04
Natural Draft, Residual Oil	(ND) LNB	27	0.31
	(MD) LNB	33	0.36
	(ND) ULNB	77	0.10
	(MD) ULNB	73	0.15
	SNCR	60	0.17
	(MD) SCR	75	0.14
	(MD) LNB+FGR	28	0.23
	(ND) LNB+SNCR	71	0.12
	(MD) LNB+SNCR	73	0.15
	(MD) LNB+SCR	83	0.09
Mechanical Draft, Distillate Oil	(MD) LNB	45	0.176
	(MD) ULNB	74	0.08
	SNCR	60	0.13
	(MD) SCR	75	0.08
	(MD) LNB+FGR	48	0.17
	(MD) LNB+SNCR	78	0.07
	(MD) LNB+SCR	92	0.03
Mechanical Draft, Residual Oil	(MD) LNB	37	0.34
	(MD) ULNB	73	0.15
	SNCR	60	0.22
	(MD) SCR	75	0.14
	(MD) LNB+FGR	34	0.36
	(MD) LNB+SNCR	75	0.14
	(MD) LNB+SCR	91	0.05

Reference: Alternative Control Techniques Document- NOx Emissions from Process Heaters (Revised), EPA-453/R-93-034, Table 2-3.

Table 3-6 State of the Art Controls for Boilers and Process Heaters
(from NJ State of the Art Manual for Boilers and Process Heaters www.state.nj.us/dep/aqpp/downloads/sota/sota12.pdf)

	Emission Rates in lb/MMBtu		
	10-50 MMBtu/hr	>50 to 75 MMBtu/hr	>75 MMBtu/hr
NOx (gas)	0.0350	0.0200	0.0100
Tech (gas)	LNB with FGR or ULNB	LNB with FGR or ULNB	LNB with FGR and/or SCR
NOx (distillate oil)	0.0600	0.0600	0.0300
Tech (distillate oil)	LNB with FGR	LNB with FGR	LNB with FGR and SCR

3.5 Cost Effectiveness of NOx Controls

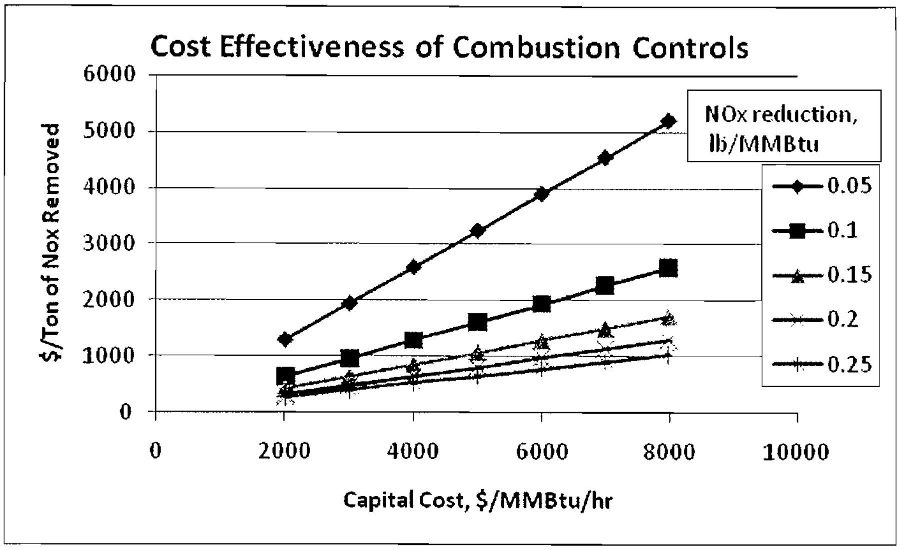
The proposed rules impose numerical emission limits on only those process heaters that are greater than100 mmBtu/hour and requires combustion tuning for heaters less than or equal to 100 mmBtu/hr. Combustion tuning is expected to reduce NOx emissions by 5 to 25 percent and results in better combustion efficiency at very low cost for smaller units affected by this rule.

There are several documents published by USEPA and STAPPA/ALAPCO that describe the cost effectiveness data for controlling NOx from process heaters. The documents include Alternative Control Techniques (ACT) Document- NOx Emissions from Process Heaters (Revised), September 1993, AirControlNet, Version 4.1, Documentation Report, dated September 2005, Controlling Nitrogen Oxides under the Clean Air Act: A Menu of Options, published in July 1994 by STAPPA/ALAPCO. In 2005 the Midwest Regional Planning Organization and LADCO published their Petroleum Refinery Best Available Retrofit Technology (BART) Engineering Analysis. Another recent STAPPA/ALAPCO document entitled "Controlling Fine Particulate Matter under the Clean air Act: A Menu of Options" dated March 2006 also provides some cost effectiveness data for process heaters.

Because the costs in $/ton of NOx are impacted by several factors such as baseline NOx level, capacity factor, retrofit difficulty, etc., the costs in $/ton shown in this report will be shown to vary widely in some cases. Since the proposed Illinois rule allows averaging, it is reasonable to expect that facility owners will install technology where it will most likely be used – high capacity factor units with higher baseline emissions. For this reason it is reasonable to assume that the expected costs for this rule would be near the lower end of the cost ranges shown.

Some of the sources cited in this section on control cost were dated several years ago, such as in the early nineties. Although there has been some inflation in the overall economy in that time, costs for many of these technologies (in terms of $/ton of NOx removed) in nominal dollars have not changed dramatically because of competition and technical advances have kept prices relatively low, especially for combustion controls. In fact, the technical advances have also improved performance, which tends to benefit (reduce) the cost effectiveness (in $/ton of NOx removed) somewhat.

Figure 3-7. Cost Effectiveness of Combustion Controls on Fired Heaters



In most cases, it is expected that combustion controls, especially ultra low NOx burners, will provide the necessary reductions at the lowest cost. In a small number of other cases, post-combustion controls may be more cost effective in providing the necessary emission controls. Figure 3-7 shows estimates of cost effectiveness (in $/ton of NOx removed) for combustion controls for various capital costs and amount of NOx reduced. The results of Figure 3-7 assume 8,000 hours per year of operation, 13% annual capital recovery factor and negligible incremental O&M cost (a reasonable assumption for most heaters). As shown, costs are generally well below $2500/ton unless NOx reduction is fairly low or capital cost is very high. However, using a typical number for capital cost of $5000/MMBtu/hr or less, under $2500/ton is very achievable in all cases except where low NOx reduction is achieved. A small amount of NOx reduction may occur in cases where heaters are already very well controlled. Cost in $/ton will also be higher if a heater operates less than 8000 hours per year. In general, refineries operate at very high capacity factors. Estimated cost would be higher at lower capacity factors. But, if a fired heater is expected to operate much less than 8000 hours per year, due to averaging under the rule, an owner is more likely to install controls on other heaters that operate at higher capacities. The results of Figure 3-7 are consistent with those of Tables 3-6a and 3-6b, which come from the 2005 study by LADCO. It is also consistent with a NJ workgroup on fired heater NOx control that found that retrofitting LNB with ULNB would provide NOx reduction at under $1000/ton. [26] As shown in Tables 3-7a and 3-7b, SCR is more costly than other approaches, and would not likely be used for compliance with the proposed rule. SNCR, especially in combination with LNB, may be able to provide NOx reduction at relatively low cost.

Other sources of cost - ACT, AirControlNet, and STAAPA/ALAPCO

USEPA's ACT and AirControlNet data provide detailed analysis on a wide variety of process heaters. Tables provided in Appendix B show estimates of cost for various model heaters, including some much smaller than affected by this rule. Generally, the costs shown for the smaller heaters in these tables will be higher than expected for the proposed Illinois rule due to the size of the units. The data has been compiled from the AirControlNet Documentation

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[26] http://www.nj.gov/dep/airworkgroups/docs/wps/SCS004A_fin.pdf . Partha Ganguli. Draft Document dated May 11, 2006.

Report. As can be seen that cost of control using ULNB is about $1500/ ton NOx reduced. Tables B-1 through B-5 are from USEPA's ACT document for model heaters. Table B-6 is developed from AirControlNet. Table B-7 is from a STAAPA/ALAPCO document. Table B-8 is a summary of data from these tables.

Although the costs in Tables B-1 through B-8 are sometimes shown in base years over ten years old, there has actually been very little cost escalation in combustion control equipment in particular over that time. This is largely due to competition in the industry along with many technological developments that have made NOx control less expensive while improving performance.

For pyrolysis heaters larger than 100 mmBtu/hr, no control cost data has been provided in the ACT document. However, the cost data for 84 mmBtu/hr ND pyrolysis heaters shows that cost is well within $2500/ton NOx reduced at a 90% capacity factor.

For ND oil-fired heaters, cost effectiveness data has been provided only for heaters with heat input of 69 mmBtu/hr. Since costs of NOx control for these process heaters are less than $2500/ton NOx reduced, it is expected that larger process heaters will also have a cost well within $2500/ton NOx reduced. For MD oil-fired process heaters, cost data is only provided for 135 mmBtu/hr process heaters. The data shows that the cost of control using LNB and SNCR will be well within $2500/ton NOx reduced. The AirControlNet data provided for small sources in Table 10 also shows that cost data for NOx control for oil-fired process heaters are well within $2500/ton NOx reduced. STAPPA/ALAPCO data for oil-fired heaters show that SCR can be used to control NOx emissions from oil-fired process heaters cost effectively.

Table 3-7a. Cost of Controls on Natural Gas Fired Heaters

Gas Fired Heater	**LNB**	
Uncontrolled emissions (tpy)	**Removal Efficiency**	**40%**
379	**Low Capital Cost**	**High Capital Cost**
Total Capital Investment (TCI)	$292,664	$3,736,339
Total Annual Costs	$187,407	$650,213
Pollutants Removed (tons/yr)	151	151
Cost per ton pollutant removed	$1,237	$4,292

Gas Fired Heater	**ULNB**	
Uncontrolled emissions (tpy)	**Efficiency**	**Efficiency**
379	**75%**	**85%**
Total Capital Investment (TCI)	$1,154,628	$1,154,628
Total Annual Costs	$315,255	$315,255
Pollutants Removed (tons/yr)	284	322
Cost per ton pollutant removed	$1,110	$979

Gas Fired Hater	**SCR**			
Uncontrolled emissions (tpy)	**Efficiency**	**70%**	**Efficiency**	**90%**
379	**Low Capital Cost**	**High Capital Cost**	**Low Capital Cost**	**High Capital Cost**
Total Capital Investment (TCI)	$1,085,350	$9,044,000	$1,085,350	$9,044,000
Total Annual Costs	$892,875	$1,962,462	$892,875	$1,962,462
Pollutants Removed (tons/yr)	265	265	341	341
Cost per ton pollutant removed	$3,368	$7,402	$2,619	$5,757

Gas Fired Heater	**LNB + SNCR**			
Uncontrolled emissions (tpy)	**Removal Efficiency**	**50%**	**Removal Efficiency**	**89%**
379	**Low Capital Cost**	**High Capital Cost**	**Low Capital Cost**	**High Capital Cost**
Total Capital Investment (TCI)	$1,000,300	$6,339,236	$1,000,300	$6,339,236
Total Annual Costs	$627,194	$1,344,709	$627,194	$1,344,709
Pollutants Removed (tons/yr)	189	189	337	337
Cost per ton pollutant removed	$3,312	$7,101	$1,861	$3,989

Gas Fired Heater	**ULNB + SCR**			
Uncontrolled emissions (tpy)	**Removal Efficiency**	**85%**	**Removal Efficiency**	**97%**
379	Low Capital Cost	High Capital Cost	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$2,239,978	$10,198,628	$2,239,978	$10,198,628
Total Annual Costs	$1,208,130	$2,277,717	$1,208,130	$2,277,717
Pollutants Removed (tons/yr)	322	322	367	367
Cost per ton pollutant removed	$3,753	$7,075	$3,289	$6,200

Table 3-7b. Cost of Controls on Natural Oil Fired Heaters

Oil Fired Heater	LNB	
Uncontrolled emissions (tpy)	**Removal Efficiency**	40%
463	**Low Capital Cost**	**High Capital Cost**
Total Capital Investment (TCI)	$292,664	$3,736,339
Total Annual Costs	$187,407	$650,213
Pollutants Removed (tons/yr)	185	185
Cost per ton pollutant removed	$1,012	$3,509

Oil Fired Heater	ULNB	
Uncontrolled emissions (tpy)	**Efficiency**	**Efficiency**
463	**75%**	**85%**
Total Capital Investment (TCI)	$1,154,628	$1,154,628
Total Annual Costs	$315,255	$315,255
Pollutants Removed (tons/yr)	347	394
Cost per ton pollutant removed	$907	$801

Oil Fired Hater	SCR			
Uncontrolled emissions (tpy)	**Efficiency**	**70%**	**Efficiency**	**90%**
463	**Low Capital Cost**	**High Capital Cost**	**Low Capital Cost**	**High Capital Cost**
Total Capital Investment (TCI)	$1,085,350	$9,044,000	$1,085,350	$9,044,000
Total Annual Costs	$1,118,413	$2,187,999	$1,118,413	$2,187,999
Pollutants Removed (tons/yr)	324	324	417	417
Cost per ton pollutant removed	$3,449	$6,748	$2,683	$5,249

Oil Fired Heater	LNB + SNCR			
Uncontrolled emissions (tpy)	**Removal Efficiency**	**50%**	**Removal Efficiency**	**89%**
463	**Low Capital Cost**	**High Capital Cost**	**Low Capital Cost**	**High Capital Cost**
Total Capital Investment (TCI)	$1,000,300	$6,339,236	$1,000,300	$6,339,236
Total Annual Costs	$705,153	$1,422,669	$705,153	$1,422,669
Pollutants Removed (tons/yr)	232	232	412	412
Cost per ton pollutant removed	$3,045	$6,143	$1,711	$3,451

Oil Fired Heater	ULNB + SCR			
Uncontrolled emissions (tpy)	**Removal Efficiency**	**85%**	**Removal Efficiency**	**97%**
463	Low Capital Cost	High Capital Cost	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$2,239,978	$10,198,628	$2,239,978	$10,198,628
Total Annual Costs	$1,433,668	$2,503,254	$1,433,668	$2,503,254
Pollutants Removed (tons/yr)	394	394	449	449
Cost per ton pollutant removed	$3,641	$6,358	$3,191	$5,572

4. Cement Kilns

4.1 Introduction

The purpose of this section is to provide a description of the source category, the mechanism of NOx formation, the technical feasibility of controls, the cost effectiveness of controls, the existing and proposed regulations, and the sources affected by the regulations.

There are four companies in Illinois which produce cement in eight kilns, three of which are long dry kilns, one short dry kiln, three preheater kilns, and one preheater/precalciner kiln. None are located in the Chicago NAA and Metro-East NAA. However, in the future, cement kilns may be built in these areas. The emission rates of Table 4-1 are proposed emission rates that apply to all cement kilns affected by this rule that have NOx emissions of 15 tons per year or more and 5 tons or more during the ozone season.

Table 4-1. Proposed Cement Kiln Emission Limits

Kiln Type	**NOx (lb/ton of clinker)**
Long Dry	5.1
Short Dry	5.1
Preheater	3.8
Preheater/Precalciner	2.8

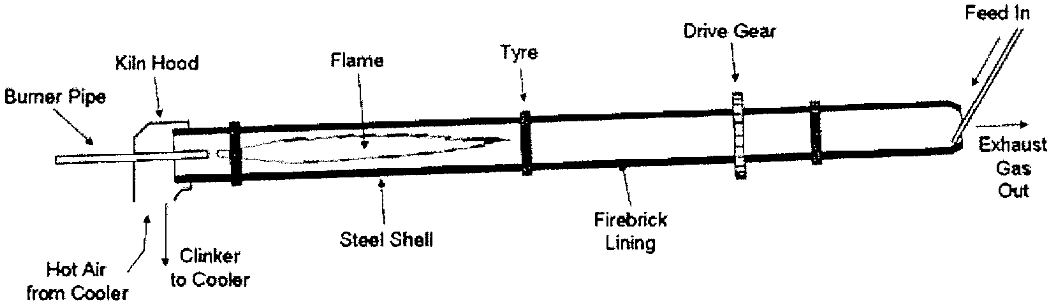
4.2 Process Description and Sources of Emissions

Cement is used in almost all construction applications, including homes, public buildings, roads, dams, bridges, tunnels etc. The hydraulic Portland cement, produced by burning a mixture of limestone, clay, and other ingredients at a high temperature, is the primary product of the cement industry. Limestone is the single largest ingredient used for making cement.

To make cement, the solid raw materials are heated to their fusion temperature, (which are typically between 2550 to 2750°F), by burning various fuels, but coal is the main fuel used in cement manufacturing. The clinkers that are produced are cooled, ground, and blended with other materials such as calcium sulfate to produce cement of right fineness. The clinkering process is the main source of NOx emissions from cement kilns.

Figure 4-1. A Rotary Cement Kiln

(Wikipedia)



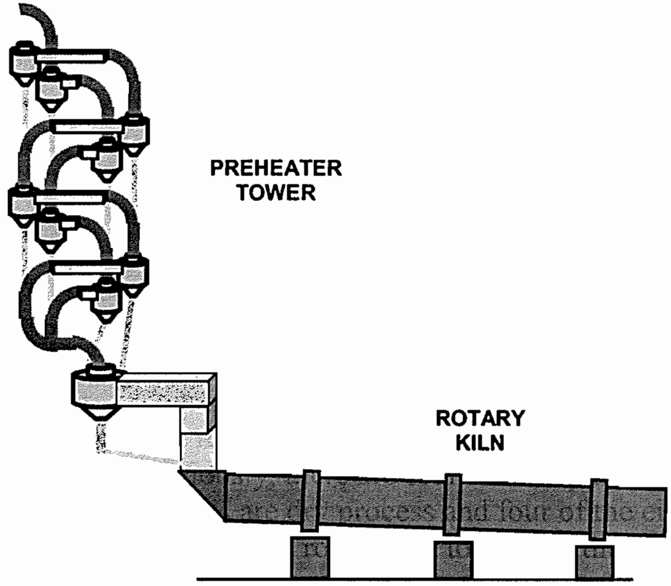
Most of the cement is produced in large rotary kilns. A rotary kiln is a refractory brick-lined cylindrical steel shell typically anywhere from about 150 feet long to several hundred feet long and 10-25 feet in diameter, such as in Figure 4-1. The kiln is slightly inclined to the horizontal and is rotated slowly at a rate of 1 to 3 revolutions per minute. The feed materials are fed at the upper end of the kiln and clinker – the product of the kiln – is discharged at the lower end. The kiln is heated by burners placed at the lower end and the hot gases flow countercurrent to the flow of raw materials. As the raw materials flow down the kiln they are gradually converted into clinkers which exit at the lower end of the kiln.

Cement can be produced either by wet process or by dry process. The choice between the wet or dry process depends upon the moisture content in the raw materials. If the moisture content of the feed materials exceeds 15 to 20 percent, a wet process is preferred. However, wet processes are energy intensive, and produce higher amount of NOx emissions per ton of clinker produced. That is why the recent trend is towards the dry process with preheater/ precalciner systems. As mentioned previously, there are four cement plants in Illinois with a total of eight kilns. All of the kilns in Illinois are dry process and four of the eight kilns have preheaters. A preheater uses the exhaust gases of the rotary kiln to preheat the feed material. Preheaters help to improve the energy efficiency and the pollutant emissions of the kiln versus kilns without preheaters. In a precalciner kiln there is fuel added to calcine the feed prior to entering the rotary section of the kiln where the material is exposed to higher temperatures to produce the clinker.

In the dry process, the raw materials are ground first and then introduced into the kiln. Drying of raw materials is carried out directly in the kiln (or in the preheater, in the case of preheater kilns). Early dry process kilns were short, and the substantial quantities of waste heat in the exit gases from such kilns were frequently used in boilers to generate electricity needed for the plant. Long dry kilns are capable of better energy efficiency than wet kilns.

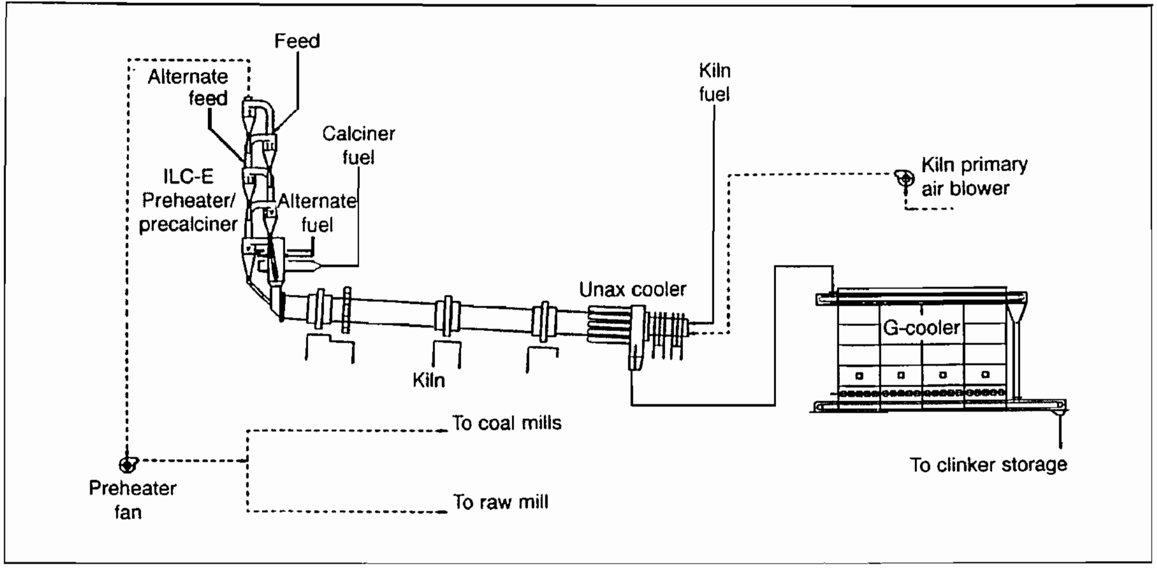
For suspension preheater kilns, a roller mill utilizes the exit gas from the preheater to dry the material in suspension in the mill. The dry, pulverized feed passes through a series of cyclones as in Figure 4-2, where it is separated and preheated several times, typically in a four-stage cyclone system. The partially calcined feed exits the preheater tower into the kiln at about 1500-1650°F.

Figure 4-2. A Preheater Kiln



In a precalciner kiln, a second burner is utilized to carry out calcination in a separate vessel attached to the preheater. The flash furnace uses preheated combustion air taken from the clinker cooler and the kiln exit gases and burns about 60 percent of the total kiln fuel. Coal, chipped tires, and other fuels may be burned, but coal is most common. The raw material is calcined about 95 percent and the gases continue to move upward through successive cyclone preheater stages. The precalciner kilns are small since only final clinkering is carried out in the rotary kiln. They are the most energy efficient of all kiln types. The burning process and clinker cooling operations are same as in other kilns. The precalciner technology is the most modern cement manufacturing technology and almost all new plants are based on these designs. Figure 4-3 shows a precalciner kiln.

Figure 4-3 A precalciner cement kiln with five-stage cyclonic precalciner [27]



4.3 Factors Affecting Uncontrolled NOx Emissions

Because cement kilns use a very high temperature combustion process, the NOx emissions from cement kilns can be rather high. As discussed earlier, there are four different types of cement kilns, namely long wet kilns, long dry kilns, preheater kilns, and preheater/precalciner kilns. The long wet and dry kilns have only one heating zone, whereas preheater and preheater/precalciners kilns have two heating zones, a primary burning zone and a secondary firing zone. Because these two zones typically have different temperatures, the factors affecting NOx formation are also somewhat different. Since Preheater and preheater/precalciner kilns are more fuel efficient, NOx emissions from such kilns are lower than conventional single burner zone dry and wet kilns.

4.3.1 NOx Formation in the Kiln Burning Zone

There are several factors which affect NOx formation in the burning zone, including combustion zone temperature, type of firing system, gas-phase residence time and oxygen concentration. However, due to the very high temperatures in the primary burn zone of a cement kiln, NOx formation is driven much more by thermal NOx than fuel NOx. Figure 4-4 shows the relationship between NOx emissions and burn-zone temperature for a kiln. The temperature of the flame strongly depends on the type of fuel burned and excess air used. While natural gas has lower fuel nitrogen, natural gas will normally result in much higher NOx than coal because the

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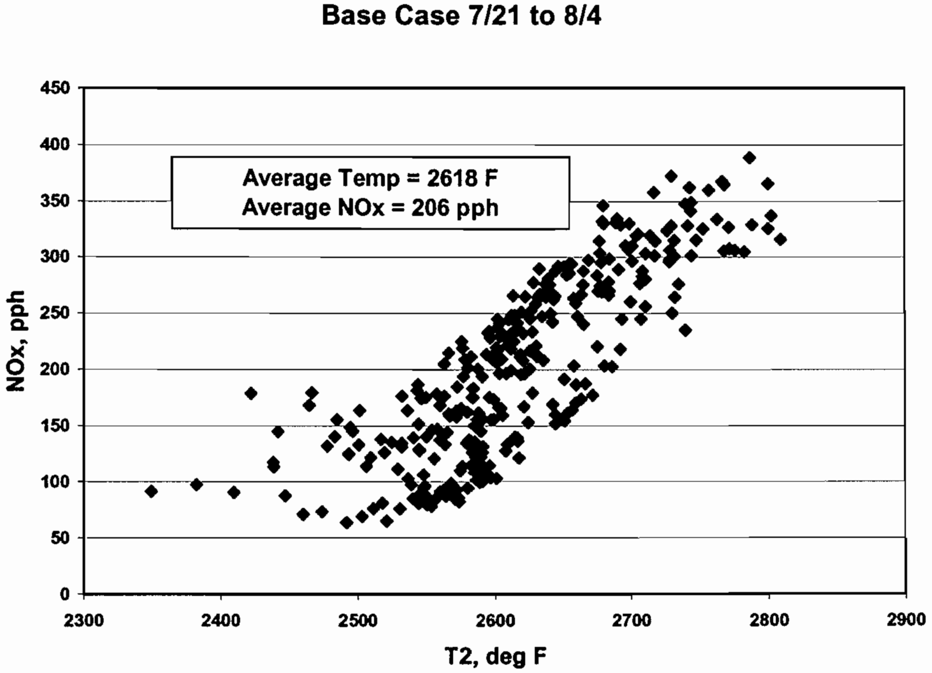
[27] Sun, W.H., Bisnett, M.J., et al. "Reduction of NOx Emissions from Cement Kiln/Calciner through the Use of the NOxOUT Process." International Specialty Conference on Waste Combustion in Boilers and Industrial Furnaces. Air and Waste Management Association. Kansas City, MO: April 21, 1994

heat release is in a smaller volume and a gas flame is less luminous than a coal flame – both contributing to higher flame temperatures and higher thermal NOx formation.

Figure 4-4. Relationship between NOx emissions and burn zone temperature for a cement kiln (data provided by Greg Mayes, Texas Industries, February 2000 to J. Staudt, Andover Technology Partners and published in NESCAUM 2000 [17])



The firing system affects the proportion of primary and secondary combustion air. Direct firing system introduces high amount of excess air and hence produces more NOx. Indirect firing system uses only a small portion of combustion air to convey fuel and hence uses less amount of primary air. Most cement kilns in the USA are direct fired. But, many have been retrofit with indirect fired burners.

Other conditions, such as excess air level, fuel type, and feed material will affect NOx emissions. The feed material may impact the temperature necessary to produce quality clinker. The dust level in the kiln will also affect NOx. Higher dust levels will reduce NOx since dust will increase radiant heat transfer.

4.3.2 NOx Formation in the Secondary Firing Zone

In the secondary firing zone of preheater and precalcining kilns, temperature ranges from 1500 to 2000°F. This temperature is lower than in the primary combustion zone of the kiln by several hundred degrees. As a result, thermal NOx generation in this zone is not a major concern. The NOx formed in this zone is largely fuel NOx.

4.3.3 Suspension Preheater Kilns with Riser Duct Firing

Preheater kilns are more energy efficient than long dry kilns. About 10-20 percent of fuel is fired into the riser duct. Because of higher energy efficiency and reduction in the amount of fuel burned at the higher clinker burning temperature, NOx emissions from preheater kilns are lower as compared to the long dry and wet kilns. Burning of coarse fuels (such as tires) into the kiln riser duct can further reduce NOx emissions from the kilns.

4.3.4 Precalcining Kiln Systems

Precalcining kilns utilize a second burner to carry out calcination in a separate vessel attached to the preheater. The flash furnace utilizes preheated combustion air drawn from the clinker cooler and kiln exhaust gases and burns about 60 percent of the total fuel. The remaining 40 percent of the fuel is combusted in the primary kiln zone. These furnaces require the least amount of energy per unit amount of clinker produced. Since the amount of fuel burned at the clinker burning temperatures is reduced considerably, NOx emissions from such furnaces are the lowest of all cement kilns. On the other hand, the NOx concentration (in ppm) in the kiln gas may be considerably higher than in preheater kilns due to longer gas retention times in the precalcining kiln burning zone combined with a very high secondary air temperature.

4.3.5 Baseline or Uncontrolled NOx Emissions

Baseline NOx emissions are strongly influenced by kiln design, fuel characteristics, peak flame temperature, and oxygen concentration. The NOx emissions data are available in the ACT document for four types of cement kilns, namely long wet kilns, long dry kilns, preheater kilns, and preheater/precalciner kilns. Table 4-1 presents proposed NOx emissions data for these cement kilns. As can be seen from the table, there are substantial variations in NOx emissions even for cement kilns of the same type.

As can be seen from Table 4-2, in general, wet kilns produce highest NOx emissions ranging from 3.6 to 19.5 lb NOx/ton of clinker with an average of 9.7 lb NOx/ton of clinker. Wet kilns also consume the most energy among different kiln types. It has been found that wet kilns burning natural gas produce more NOx than those burning coal.

Table 4-2: NOx Emission Factors for Different Kiln Types

Cement Kiln Type	Heat Input Requirement (mmBtu/Ton Clinker)	Average NOx Emission Rate (lb/ton Clinker)	Range of NOx Emissions (lb/Ton of Clinker)
Long Wet Kiln	6.0	9.7	3.6 – 19.5
Long Dry Kiln	4.5	8.6	6.1 – 10.5
Short Dry Kiln*	Not Available	Not Available	Not Available
Preheater Kiln	3.8	5.9	2.5 – 11.7
Precalciner Kiln	3.3	3.8	0.9 – 7.0

* For short dry kilns, it is safe to assume that heat input requirements and NOx emissions are similar as for long dry kilns.

As compared to long wet kilns, long dry kilns typically consume about 25 percent less energy. They also produce typically about 12 percent lower emissions compared to long wet kilns. Since long wet and long dry kilns are similar in terms of structure and firing of fuels, lower NOx emission rates for long dry kilns may be partly attributed to differences in energy consumption. NOx emissions from long dry kilns are in the range of 6.1 to 10.5 lb/ton with an average value of 8.6 lb/ton of clinker produced.

Preheater kilns produce NOx emissions in the range of 2.5 to 11.7 lb/ton with an average value of 5.9 lb/ton of clinkers produced. The highest NOx rates were found in natural gas burning kilns. Since combustion of part of the fuel is done in a preheater and total fuel consumption is lower for a preheater kiln than a long dry kiln, preheater kilns produce lower amount of NOx as compared to long wet and long dry kilns.

Precalciner kilns produce the least amount of NOx emissions ranging from 0.9 to 7.0 with an average of 3.8 lb NOx/ton of clinker. These kilns are also the most energy efficient with an average energy consumption of 3.3 million Btu/ton of clinker. Because of overall lower fuel consumption and lower fuel consumption in the kiln, these kilns produce lower NOx emissions as compared to other types of kilns discussed above.

4.4 Technical Feasibility of NOx Controls

For any given type of the cement kiln, the amount of NOx formed is directly related to the amount of energy consumed in the cement-making process. Thus, the measures that improve the energy efficiency of this process should reduce NOx emissions in terms of pounds ("lb") of NOx per ton of product. With rising costs of energy and the very competitive cement market, greater attention is being paid to reduce over-burning of clinker, improving gas-solids heat transfer and increasing overall energy efficiency.

In its document Alternative Control Techniques Document--NOx Emissions from Cement Manufacturing, EPA-453/R-94-004 ("ACT"), March 1994, (See Reference 3) USEPA has identified control techniques in detail. NOx control approaches applicable to the cement industry may be grouped into two categories:

- Combustion control approaches where the emphasis is on reducing NOx formation, and
- Post-combustion control approaches which destroy the NOx formed in the combustion process.

4.4.1 Combustion Controls

4.4.1.1 Combustion Zone Control of Temperature and Excess Air

NOx emissions from a cement kiln are mainly a function of temperature and the amount of nitrogen and oxygen that can react together. Because the high temperature needed to convert the raw materials into clinker is very conducive to NOx formation, significant NOx reductions can be obtained by lowering kiln operating temperatures, and by lowering the excess air ratio thus decreasing the amounts of nitrogen and oxygen available for reacting. On the other hand, a minimum operating temperature is necessary to maintain the quality of the cement that is being produced.

The solution to NOx via combustion zone control of temperature and excess air is therefore to determine the minimum excess air ratio necessary for product quality, to maintain this ratio by continuously monitoring oxygen and carbon monoxide levels in the exhaust, and to keep the temperature low by also continuously monitoring NOx in order to also maintain low NOx concentrations. This can be achieved by a monitoring feedback control system for excess air. According to the ACT, combustion zone control of temperature and excess air can provide approximately a 15% reduction of NOx from a cement kiln.

4.4.1.2 Process Modifications and Process Control

Process modifications and process control are designed to reduce emissions by minimizing the amount of heat needed to produce a ton of clinker.

One such technique is a reformulation of kiln feed to obtain lower alkali content in as much as the necessary removal of alkali by volatilization in clinker production requires heat. This is achievable with the use of steel-making slag as a feedstock. One such technology is known as Cemstar and has been shown to reduce NOx about 20%.[17] According to the cement ACT, in some cases such reformulation has reduced heat requirements by as much as 15%, which contribute to lower NOx emissions. Reformulation also contributes to lower firing temperature - reducing NOx further - and will also improve kiln output. Reformulation, however, is dependent on the availability of a low alkali raw material mix and therefore may not be viable for all kilns.

Reductions of NOx emissions can also be obtained by increasing thermal efficiency. The use of a good system of chains attached to the kiln walls to transfer heat from the hot gases above to the process material below as the kiln rotates can significantly improve thermal efficiency, as can increasing clinker cooler heat recovery by use of additional secondary air. Prevention of the leaking of cool air into the kiln, and recycling cement dust from the dust collectors are two more ways to increase thermal efficiency. Increasing thermal efficiency, however, is unlikely to reduce NOx emissions sufficiently to meet the requirements of the Illinois EPA's regulatory proposal. Furthermore, most Illinois cement kilns have already optimized thermal efficiency for economic reasons.

Another way of improving thermal efficiency and NOx emissions is improved process control using automated controls. Figures 4-5a and 4-5b help explain how use of improved process control using a Linkman process controller reduced NOx emissions by about 55% for Ash Grove Cement. As shown in Figure 4-5a, without the process control, the NOx emission rate was distributed over a very wide distribution (NOx is on the x axis and frequency of NOx is plotted vertically). In Figure 4-5b, with the process control, NOx emissions are maintained over a much more narrow range that avoids the very high NOx emissions excursions shown in 4-5a. In the case of Ash Grove Cement, this project justified itself purely on the basis of improved process control without the benefit of NOx emissions.[17]

4.4.1.3 Changing Kiln Fuel

Coal and natural gas are the most commonly used fuels for cement kilns in the United States. Although coal contains considerable nitrogen, and natural gas is virtually nitrogen free, NOx emissions from kilns burning natural gas are much higher than the emissions from kilns burning coal because in kiln conditions natural gas flames are considerably hotter than coal flames. In Illinois, however, all cement kilns burn coal rather than natural gas. On the other hand, some Illinois kilns burn at times other fuels, e.g. petroleum coke that are lower in nitrogen content than coal, and moreover burn with cooler flame temperatures. Increased use of such fuel will lower NOx emissions somewhat, but are unlikely to by themselves achieve the reduction required by the Illinois EPA's proposal.

Figure 4-5a. Baseline at Ash Grove Cement

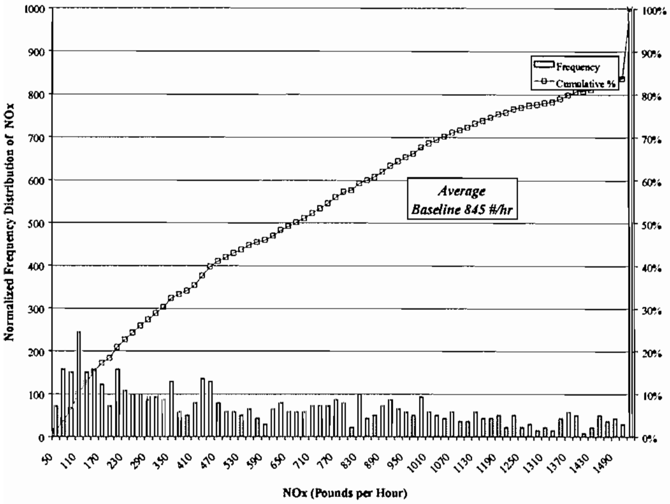
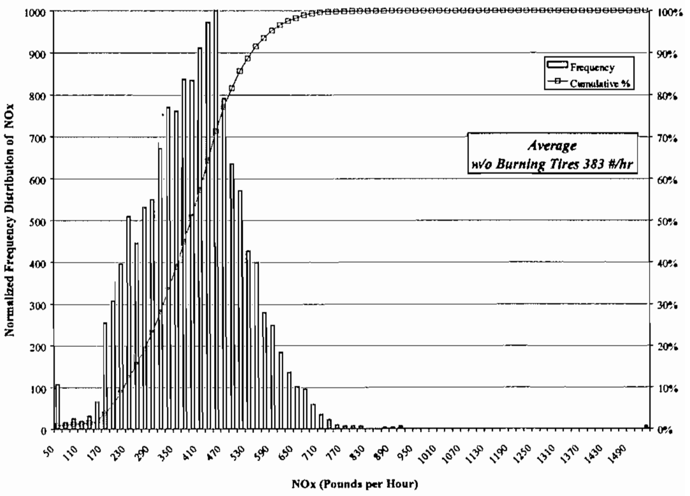


Figure 4-5b. With process control at Ash Grove Cement



Both Figures from NESCAUM 2000 Report

4.4.1.4 Staging of Combustion

Control of NOx from cement kilns can also be achieved by allowing the combustion to proceed in two or more stages. In the first stage, there is a shortage of combustion air. This allows a reaching of the high temperature necessary to complete conversion of the calcined raw materials, via chemical reactions, into clinker while minimizing NOx formation because of a shortage of oxygen. (Note that in countercurrent flow the combustion begins at the point where the material flows through the kiln ends).

In the second and any following stages, additional air is added that allows combustion to proceed to completion, but at a temperature which is lower, because of dilution of the primary combustion air with cooler secondary air. Thus in the second stage, NOx is also minimized, this time by lower temperature in spite of the abundance of both nitrogen and oxygen. This lower temperature, however, is still sufficient to allow calcination to be completed.

4.4.1.5 Staging Combustion by Use of Indirect Firing

In coal-fired kilns, combustion can be staged and NOx reductions achieved by employing indirect, rather than direct, firing in the kiln. Older kilns use direct firing, where the ground coal is blown directly from the mill to the kiln flame zone. In indirect firing, the finely ground coal is collected and then blown into the kiln. This enables lower primary air levels to be used and also enables low NOx burners in both the primary burn zone as well as in the precalciner (for preheater/precalciner kilns). Conversion to indirect firing is necessary for the use of low NOx burners that use air staging. As a result, low NOx burners – using staged air methods – can and have been employed on kilns using indirect firing.

Moreover, low NOx burners with indirect firing can be combined with other combustion controls, such as flue gas recirculation and mid-kiln firing. At California Portland Cement, low

NOx burners with indirect firing were added to two 1150 TPD long dry kilns. The $7 million capital project reduced the NOx emissions from 5.4 lb/ton clinker to 2.73 lb/ton of clinker – roughly 49%.[17]

4.4.1.6 Flue Gas Recirculation

Flue gas recirculation (FGR) is a method that is effective when combined with low NOx burners in reducing NOx emissions from preheater/precalciner kilns because a substantial amount of fuel is used in the precalciner. Also, FGR on such kilns is not difficult since the flue gas ductwork is in the vicinity of the precalciner. FGR would not likely be employed in the primary firing zone due to the extent of ductwork needed.

4.4.1.7 Staging Combustion with Low NOx Burners

Use of low NOx burners to reduce NOx is only possible if indirect firing is used; this is a frequently used approach for NOx control. The ACT gives a NOx removal efficiency of from 20-30% for retrofit installation of low NOx burners on a cement kiln.

4.4.1.8 Staging Combustion by Conversion to Preheater or Preheater/ Precalciner Designs

As explained earlier, preheater and preheater/precalciner kilns have lower NOx emissions. The emissions decrease for conversion from a long dry design to a preheater design is about 26% using the average of the emission factors provided in the ACT and AP-42 Compilation of Air Pollutant Emission Factors (See Reference 4). Similarly, the average decrease for conversion from a long dry kiln to a preheater/precalciner design is about 45%. Again, according to the same factors, the average decrease in NOx emissions from a preheater to a preheater/precalciner design is about 27.5%. Converting to a preheater or preheater/precalciner kiln is a major capital expense. But, depending upon the expected life of the kiln, the long term savings from the efficiency benefit could justify the investment.

4.4.1.9 Staging Combustion in Preheater and Preheater/ Precalciner Kilns

Although preheater kilns already employ a degree of combustion staging that lowers NOx emissions as compared to long dry kilns, a further degree of staging with consequent NOx reductions can be realized by firing some of the fuel into the riser duct to the preheater.

Similarly, in preheater/precalciner designs further staging can be achieved by injecting part of the calciner fuel in the kiln exhaust gas entering the calciner. This technique includes use of low NOx burners and an addition of tertiary air at a later point to complete combustion of the calciner fuel.

4.4.1.10 Staging Combustion by Mid-Kiln Firing

Combustion can also be staged by mid-kiln injection of some of the fuel needed for the production of clinker. Such fuel will therefore be burned at the mid-kiln temperature of 1,600-1,800°F, which is an adequate temperature to allow the completion of calcination, such that the calcined material is ready to be burned into clinker at the higher temperatures near the discharge to the clinker cooler. The mid-kiln 1,600-1,800° degree temperatures are not conducive to NOx formation, so less NOx is formed than when all the fuel is burned at the higher temperatures near the discharge of the kiln. Additionally, some of the NOx formed near the discharge may be changed back to nitrogen and oxygen when the combustion gases reach the fuel-rich mid-kiln conditions.

Fuel can be introduced into the kiln's mid-section by placing a burner into the kiln's side. The entrance to the burner is closed, but fitted with a device to open the burner to the fuel supply when its closed end contacts that supply once per kiln revolution. Since the mid-kiln fuel flow is therefore intermittent, solid or other slow burning fuel is used to maintain heat continuity. Used tires are a common fuel for this purpose because they burn slowly and kiln operators may receive a tipping fee for taking the tires. Figure 4-6 shows a kiln with mid-kiln firing of tires. In this case the kiln also uses downstream air mixing technology to improve combustion. The ACT investigated the effects of mid-kiln firing of whole tires on NOx emissions and reported that NOx emissions reductions of 20 to 40% are possible. Some test results from kilns are shown in Figure 4-7. In addition to this, some manufacturers and suppliers of mid-kiln firing systems claim that further NOx emissions reduction can be achieved by installing a mix-air fan downstream from the fuel injection point, as shown in Figure 4-6.

The addition of mixing air to mid-kiln firing has been shown to improve NOx emissions by providing more consistent combustion and emissions. Figures 4-8a and 4-8b are a comparison of the frequency distribution of NOx emissions for a kiln that is equipped with mid-kiln firing without and with the use of mixing air. As shown in Figure 4-8b, mixing air reduces the variation in NOx emissions and results in a narrower frequency distribution, avoiding the high NOx levels that periodically occur without the mixing air that are apparent in Figure 4-8a.

Figure 4-6. Mid-Kiln Firing of Tires
(http://www.cadencerecycling.com/pdf/6-PageComplete.pdf)

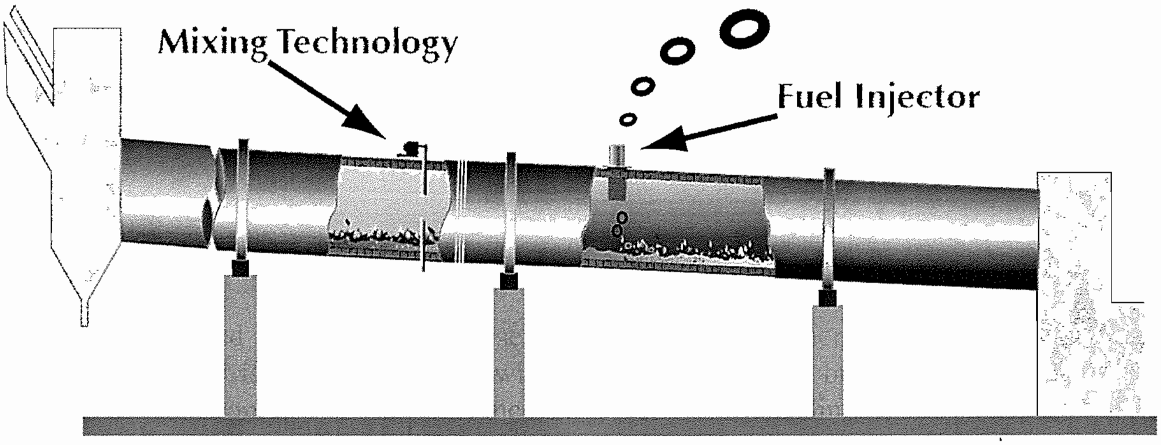
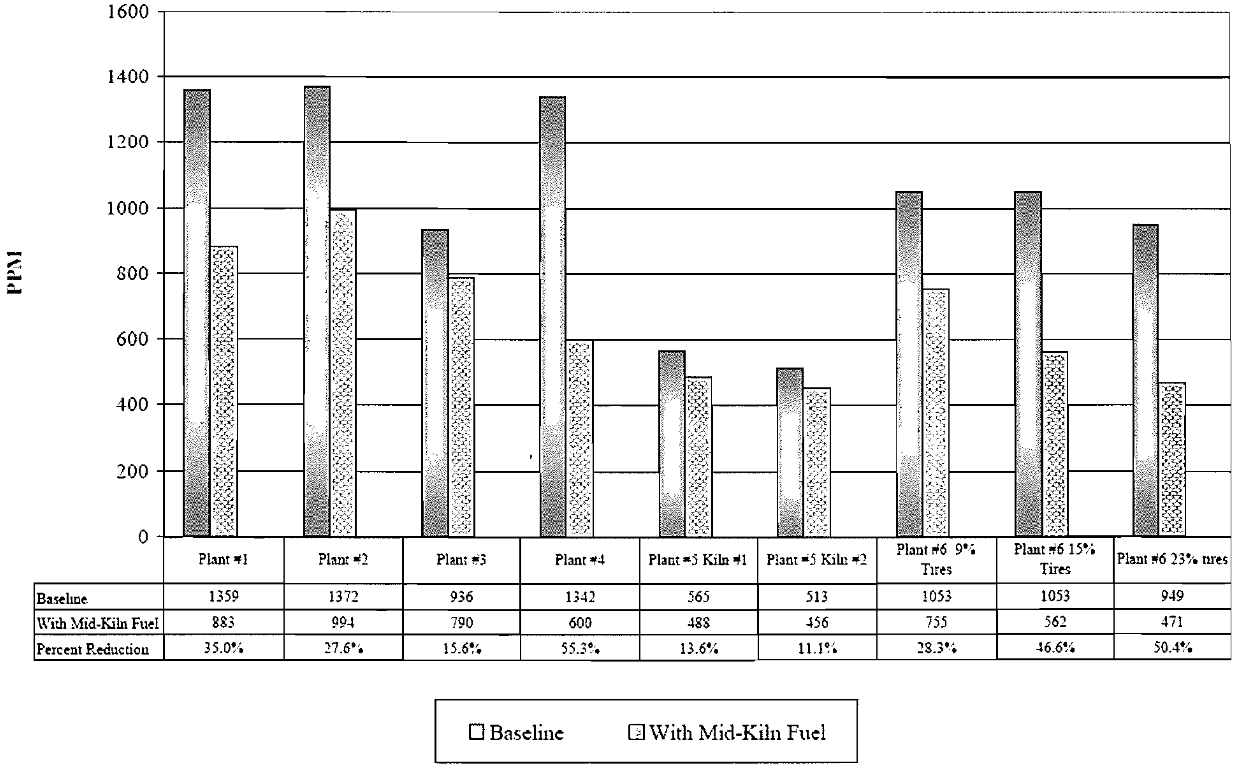


Figure 4-7. Comparison of NOx emissions without and with mid-kiln firing at several plants (Hansen, E., "Staged Combustion for NOx Reduction Using High Pressure Air Injection", http://www.cadencerecycling.com/pdf/IEEE2002.pdf)



	Plant #1	Plant #2	Plant #3	Plant #4	Plant #5 Kiln #1	Plant #5 Kiln #2	Plant #6 9% Tires	Plant #6 15% Tires	Plant #6 23% tires
Baseline	1359	1372	936	1342	565	513	1053	1053	949
With Mid-Kiln Fuel	883	994	790	600	488	456	755	562	471
Percent Reduction	35.0%	27.6%	15.6%	55.3%	13.6%	11.1%	28.3%	46.6%	50.4%

Figure 4-8a Frequency Histogram of NOx Values on Cement Kiln with Mid-Kiln Tire Injection (Without Mixing Air)

Letter and enclosed technical data and documents from Eric Hansen, Ash Grove Cement, to J. Staudt, Andover Technology Partners, January 17, 2000 and later referenced in NESCAUM 2000

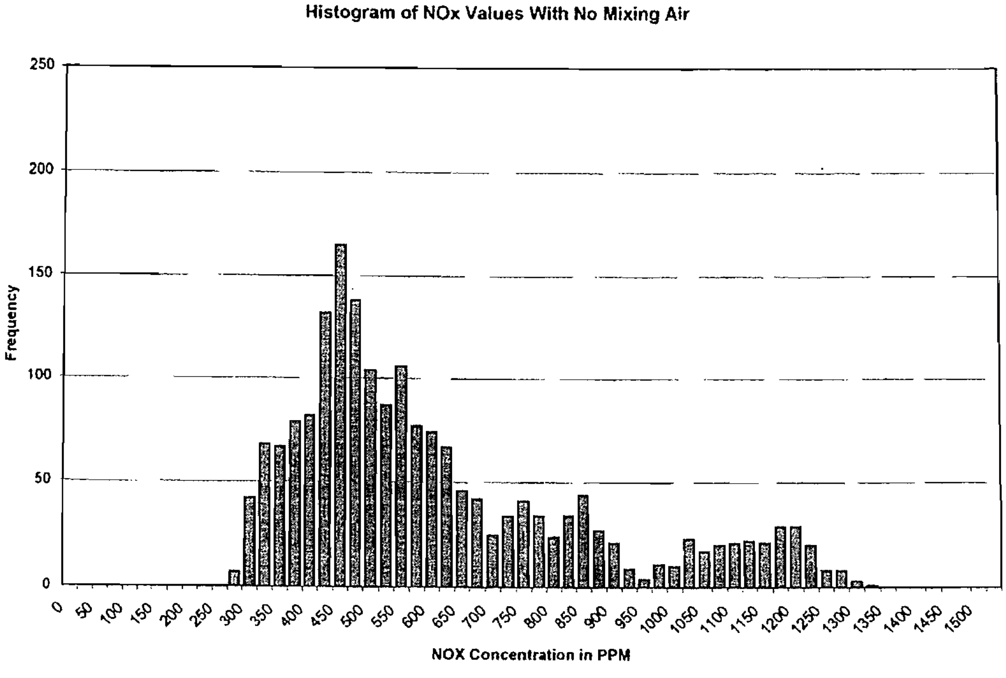
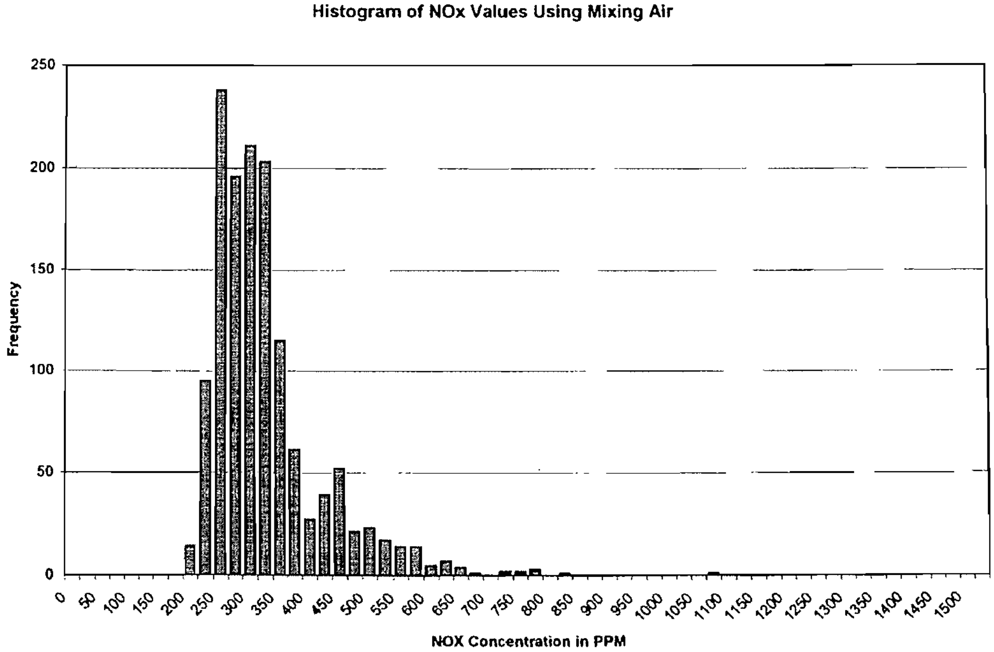


Figure 4-8b Frequency Histogram of NOx Values for the same Cement Kiln with Mid-Kiln Tire Injection as in Figure 4-8a (With Mixing Air)



4.4.2 Post Combustion Controls

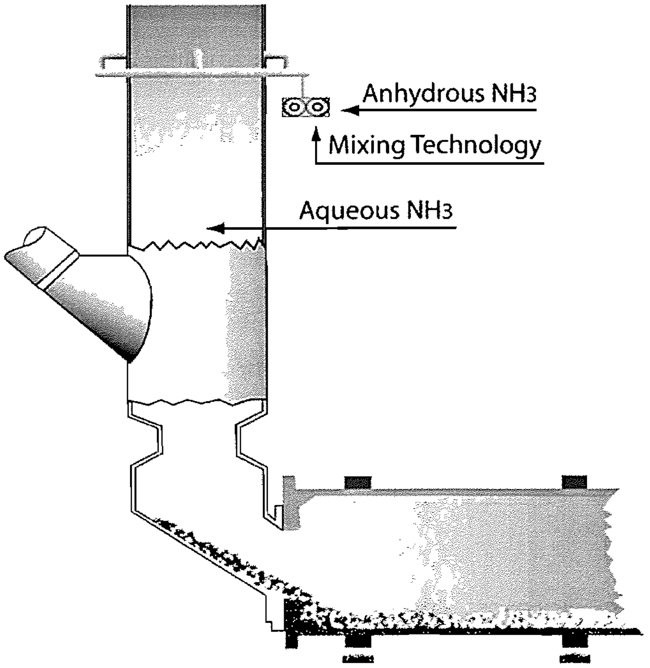
Post combustion controls reduce the NOx that is formed in the combustion process. There are two methods that might be applicable to cement kilns.

4.4.2.1 Selective Catalytic Reduction (SCR)

SCR is a process using ammonia, or some other reducing agent, in the presence of a catalyst to selectively reduce NOx emissions from exhaust gasses. Usually anhydrous ammonia is injected through a grid system into the hot flue gas, which is then passed through a catalyst bed wherein the NOx in the flue gas undergoes reduction. As the two principle components of NOx are nitric oxide and nitrogen dioxide, the two principle reactions are nitric oxide plus ammonia plus oxygen yielding nitrogen and water vapor, and nitrogen dioxide plus ammonia plus oxygen yielding nitrogen and water vapor.

SCR is rarely retrofitted on cement kilns because it tends to cost more than other available methods. It would not be necessary to achieve the emissions levels of Table 4-1. However, SCR can provide high levels of NOx reduction. SCR does require installation at a point in the gas stream where the temperature is in the right range for the catalyst. This makes it more difficult to install on existing facilities than other approaches. However, the Lake Michigan Air Director's Consortium (LADCO) has identified it as a candidate technology for Best Available Retrofit Technology (BART).[28]

Figure 4-9. Example SNCR injection on a preheater kiln
http://www.cadencerecycling.com/pdf/6-PageComplete.pdf



4.4.2.2 Selective Non-catalytic Reduction (SNCR)

SNCR accomplishes the same chemical reactions as SCR in order to reduce NOx to nitrogen. It accomplishes this by injecting reagent (ammonia or urea) at higher temperatures. The simplicity of the equipment makes SNCR relatively easy and inexpensive to retrofit. However, SNCR requires a specific temperature window in order to achieve proper NOx reduction.

SNCR has been used in preheater and precalciner kilns, which have better access to the proper temperature window for SNCR NOx reduction, as shown in Figure 4-9.[29] However, on long kilns, access to the proper temperature window on the

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[28] Sabo, E., "Candidate Control Measures for Cement Plants", LADCO/MRPO, Regional Air Quality Workshop June 28, 2005

[29] Sun, W.H., Bisnett, M.J., et al. "Reduction of NOx Emissions from Cement Kiln/Calciner through the Use of the NOxOUT Process." International Specialty Conference on Waste Combustion in Boilers and Industrial Furnaces. Air and Waste Management Association. Kansas City, MO: April 21, 1994.

rotary kiln is more difficult. Some companies have developed approaches for addressing this.

Expected NOx reductions from SNCR range from 30-70% on kilns where there is access to the proper injection temperature.

A related technology is biosolids injection (BSI). In BSI, sludge is injected into the preheater or precalciner at a similar point as ammonia would be injected in SNCR. The sludge releases ammonia and acts as an SNCR reagent. At Mitsubishi Cement in California, BSI provided 50% NOx reduction (NESCAUM 2000). BSI may not be as easily applied as SNCR because of the material handling and source of biosolids needed.[17]

Table 4-3 summarizes the NOx emissions reductions potential of various control strategies for cement kilns.

Table 4-3: Approximate Expected NOx Emissions Reduction with Various NOx Control Technologies

NOx Control Technology	Expected NOx Emissions Reduction (%)
Process Modifications	<25
Indirect Firing with Low - NOx Burner	20-30
Staged Combustion in Precalciner Kilns	30-45
Mid - Kiln Firing of Whole Tires in Long Kiln	20-40
Indirect Firing with Mid Kiln firing	40-60
SNCR in Preheater/Precalciner Kilns	30-70
SCR (based on data from coal - fired boilers)	80-90

4.5 Cost Effectiveness of NOx Controls

The USEPAhas prepared a number of cost effectiveness estimates for controlling NOx emissions from cement plants. Two of the most recent and significant estimates are contained in the federal ACT for cement plants and the Regulatory Impact Analysis (RIA) for the NOx SIP Call, FIP, and Section 126 Petitions (See References 3 and 5). The Illinois EPA is relying on these two documents to estimate the cost effectiveness of controlling Illinois NOx sources to the level proposed by this rulemaking. Other studies include NESCAUM's 2000 report and recent work by LADCO (2005).

Tables 4-4a and 4-4b show the results of cost effectiveness calculations performed in NESCAUM's 2000 report based upon actual case studies in that report. As shown, indirect firing with mid-kiln firing provided roughly 50% NOx reduction, and the cost of control was under $1000/ton. Higher costs would result with lower capacity factors. Generally, cement kilns operate at high capacity factors. Depending upon the ability to receive a tipping fee for tires (the most common mid-kiln fuel, but coal can be used), it may be possible to reduce operating costs through these NOx control measures. CemStar is another technology that may reduce operating costs while also reducing NOx. Because there are economic benefits even without accounting for NOx reduction benefits, some facility owners have elected to install

CemStar or to install mid-kiln firing systems even absent NOx control requirements. The economics of CemStar are shown in Table 4-5.

Table 4-4a. Cost Effectiveness Indirect Firing and Mid Kiln Tire Firing on Long-Dry Kiln - 49% Reduction from 5.0 lb/ton clinker on two 96 Ton/hr kilns, (NESCAUM 2000 report)

	Capacity Factor	
	0.65	0.85
No Tipping Fee		
Annual Control, \$/ton NOx	\$1,114	\$736
Annual Control, \$/ton clinker	\$1.48	\$0.97
\$20/ton Tipping Fee.		
Annual Control, \$/ton NOx	\$891	\$513
Annual Control, \$/ton clinker	\$1.18	\$0.68
\$75/ton Tipping Fee.		
Annual Control, \$/ton NOx	\$277	(\$101)
Annual Control, \$/ton clinker	\$0.37	(\$0.13)

Notes:

- Values in parentheses indicate a net economic benefit to the user rather than net economic cost for using this technology

- It is assumed that the technologies do not significantly impact production. This assumption may not be correct in some cases and this impact should be considered when appropriate.

Table 4-4b. Cost Effectiveness Mid Kiln Tire Firing on Long-Dry Kiln - 20% Reduction from 5.0 lb/ton clinker on two 40 Ton/hr Kilns.

Time Period of Control and Units of Cost	Capacity Factor		
	0.45	0.65	0.85
No tipping fee			
Annual Control, \$/ton NOx	(\$969)	(\$1,435)	(\$1,681)
Annual Control, \$/ton clinker	(\$0.48)	(\$0.72)	(\$0.84)
\$20/ton tipping fee.			
Seasonal control, \$/ton NOx	(\$5,164)	(\$6,281)	(\$6,873)
Seasonal Control, \$/ton clinker	(\$1.08)	(\$1.31)	(\$1.43)
Annual Control, \$/ton NOx	(\$2,151)	(\$2,617)	(\$2,864)
Annual Control, \$/ton clinker	(\$1.08)	(\$1.31)	(\$1.43)
\$75/ton tipping fee.			
Seasonal control, \$/ton NOx	(\$12,966)	(\$14,084)	(\$14,675)
Seasonal Control, \$/ton clinker	(\$2.70)	(\$2.93)	(\$3.06)
Annual Control, \$/ton NOx	(\$5,403)	(\$5,868)	(\$6,115)
Annual Control, \$/ton clinker	(\$2.70)	(\$2.93)	(\$3.06)

Notes:

- Values in parentheses indicate a net economic benefit to the user rather than net economic cost for using this technology

- It is assumed that the technologies do not significantly impact production. This assumption may not be correct in some cases and this impact should be considered when appropriate.

Table 4-5 Cost Effectiveness of CemStar - 20% reduction from 200 lbNOx/hr/kiln (800 pph total) on four 40-Ton/hr wet process Kilns, (NESCAUM 2000 report)

Units of Cost	Capacity Factor	
	0.65	0.85
net clinker value = $15/ton		
Annual Control, $/ton NOx	$431	$365
Annual Control, $/ton clinker	$0.22	$0.18
net clinker value = $30/ton		
Annual Control, $/ton NOx	($1,845)	($1,910)
Annual Control, $/ton clinker	($0.92)	($0.96)
net clinker value = $50/ton		
Annual Control, $/ton NOx	($4,879)	($4,945)
Annual Control, $/ton clinker	($2.44)	($2.47)

Notes:
- Values in parentheses indicate a net economic benefit to the user rather than net economic cost for using this technology

SNCR cost effectiveness was assessed in the 2000 report by NESCAUM, including the estimate in Table 4-6 based upon a case study in that report.

Table 4-6 Cost Effectiveness of SNCR on 150 Ton/hr Precalciner Kiln, 45% NOx Reduction from 700 pph (NESCAUM 2000 Report)

Units of Cost	Capacity Factor	
	0.65	0.85
Annual Control, $/ton NOx	$725	$675
Annual Control, $/ton clinker	$0.76	$0.71

LADCO's analysis[28] showed costs for technologies it classifies as reasonably available. For NOx, it assumes that sources could combine mid-kiln firing with low-NOx burners or apply SNCR technologies. These technologies showed average emission reductions about 50 percent from uncontrolled levels at an estimated control cost of -$310/ton to $2500/ton. By LADCO's estimate, use of SCR, which would be a BART approach in its analysis, cost would be between $1500/ton and $2000/ton of NOx.

STAPPA/ALAPCO in 2006 assessed the performance and cost effectiveness of various control technologies on cement kilns. (See footnote 21). The results are shown in Table 4-7. As shown, the results are generally consistent with those of the NESCAUM report. Additionally, Table 4-8 shows estimates based upon USEPA estimates made in 1999 and represented in 1990 dollars and Table 4-9 shows estimates by USEPA in 2006 using AirControlNet. As shown, the costs are generally very consistent from one estimate to the other.

Table 4-7. Cost and Performance of NOx Control Measures on Cement Kilns.[21]

NO$_x$ Control Technology Performance

Technology	Average Emissions Reduction (%)	Range of Emissions Reductions (%)	Average Annual Cost-Effectiveness ($ per Ton NO$_x$ Reduced)[a]	Range of Annual Cost-Effectiveness ($ per Ton NO$_x$ Reduced)[a]
CemStar	33	25–40	550	ND
Indirect firing with a low-NO$_x$ burner[b]	27	4–47	440	300–620
Long dry kiln with low-NO$_x$ burner[c]	40	ND	ND	166–1,299
Preheater kiln with low-NO$_x$ burner[c]	40	ND	ND	175–1,201
Mid-kiln firing (wet kilns only)	41	28–59	55	(460)–730
Mid-kiln firing (dry kilns only)	33	11–55		
SNCR[d]	40	10–50	1,750	1,000–2,500
SNCR[e]	ND	31–83	ND	605–700
SCR[f]	90	85–95	2,700	ND
SCR[e]	ND	31–83	ND	530–1,135
Long dry kiln with SCR[c]	ND	70–90	ND	586–1,902
Preheater kiln with SCR[c]	ND	70–90	ND	504–1,232

ND = No Data

a. In 1997$, except where noted.

b. Converting a direct-fired kiln to an indirect-fired kiln and retrofitting with an LNB roughly doubles the cost effectiveness.

c. From LADCO, 2005. Cost-effectiveness in 2004$.

d. These estimates are based on the use of an SNCR technology called NO$_x$-OUT® at three facilities.

e. From Haug, 2002. Emissions reductions range includes all data from the study. Cost-effectiveness in 2002$. Junker, 2000 supports SNCR emissions reductions of 80-85%.

f. From European Commission, 2000; based on one demonstration project in the Netherlands. Cost effectiveness in 2000$.

Table 4-8. Cost Effectiveness of NOx Controls (1990 dollars)
USEPA, Nitrogen Oxides – Why and How They are Controlled, EPA 456/F-99-006R, November 1999, http://www.epa.gov/ttn/catc/dir1/fnoxdoc.pdf

Kiln Type	Technology	Red'n	Ozone Season $/ton	Est. Annual $/ton*
Cement Manufacturing - Dry	Mid-Kiln Firing	30	1,110	460
Cement Manufacturing - Dry	LNB	30	1,340	560
Cement Manufacturing - Dry	SNCR - Urea Based	50	1,280	770**
Cement Manufacturing - Dry	SNCR - NH3 Based	50	1,490	800**
Cement Manufacturing - Dry	SCR	80	6,850	2970**

*estimated from Ozone Season estimate. Capital cost contribution of ozone season cost multiplied by 5/12
** assumes $300/ton operating cost for NH3 SNCR and $400/ton of NOx operating cost for urea SNCR and $200/ton of NOx for SCR

Table 4-9. 2006 Cost Estimates by USEPA Using AirControlNet
8/21/06 -- Bill Neuffer, USEPA
http://www.epa.gov/groundlevelozone/SIPToolkit/documents/stationary_nox_list.pdf

Source category	**Identified by**	**Potential measure/control technology**	**Efficiency(%)**	**Cost effectiveness ($/T)**
Cement plants -existing kilns – low-NOx burners, mid-kiln firing(MKF). SNCR may be possible New kilns – SNCR plus staged combustion; SCR may be feasible	LADCO, OTC, CAN; STAPPA	LNB MKF SNCR +SC	25-30 30-35 50 -70	300 – 620 -460 – 720 770

4.5.1 ACT Cost Effectiveness

The ACT is an older estimate of costs. However, the results are shown for comparison and for the technologies of interest, they are generally comparable. Three cost considerations are presented in the federal ACT document: total capital costs, total annual costs, and cost effectiveness. The total capital cost is the sum of the purchased equipment costs, direct installation costs, indirect installation costs, and contingency costs. Annual costs consist of the direct operating costs of materials and labor for maintenance, operation, utilities, and material replacement and disposal and indirect operating charges including plant overhead, general administration, and capital recovery charges. Cost effectiveness, in dollars/ton of NOx removed, is calculated for each control technique by dividing the total annual cost by the annual tons of NOx removed.

The ACT describes the costs of various NOx controls applicable to the cement kilns. Depending on the type and size of the kiln, the cost effectiveness of each control varies from a few hundred to several thousands dollars per ton of NOx removed. Since the NOx SIP Call was based on controlling large cement kilns (i.e., a cement kiln that emitted more than one ton of NOx per 1995 average summer day) data for those sizes of kilns were extracted from the ACT.

Table 4-10 summarizes the cost effectiveness of various control options for large cement kilns from AirControlNet and Table 4-11 shows cost effectiveness numbers from the ACT.

Based on the ACT, there are a number of control options available which achieve the control levels indicated in Table 4-1. The cost effectiveness ranges from $220 to $4870/ton of NOx removed, based on the total annual cost divided by total annual NOx reductions.

Table 4-10: Cost Effectiveness of Various Control Options for Cement Kilns (Source: AirControlNet. Cost Year: 1990)

NOx Control Type	Kiln Type	NOx Reduction %	Cost Effectiveness ($/ton NOx removed)	
			Range	Typical
Low NOx Burner	Long wet or dry	25	300-620	440
Mid Kiln Firing	Long wet or dry	25	-460 to 730	55*
SNCR	Long dry	50	--	850
SCR	Long wet	80	--	2880
SCR	Long dry	80	--	3370

*The value is reported as $60/ton in (10)Vistas BART Data

Table 4-11: Cost Effectiveness of Various Control Options for Cement Kilns (Source: ACT. Cost Year: 1992)

NOx Control Type	Kiln Type	Kiln Capacity (tons clinker/hr)	NOx Reduction %	Cost Effectiveness ($/ton NOx removed)
Low NOx Burner	Long wet indirect-fired	30	25	310
	Long wet indirect-fired	50	25	230
	Long dry indirect-fired	25	25	370
	Long dry indirect-fired	40	25	260
	Preheater indirect-fired	40	25	370
	Preheater indirect-fired	70	25	260
	Precalciner indirect-fired	100	25	270
	Precalciner indirect-fired	150	25	220
Low NOx Burner	Long wet direct-fired	30	25	1130
	Long wet direct-fired	50	25	880
	Long dry direct-fired	25	25	1270
	Long dry direct-fired	40	25	970
	Preheater direct-fired	40	25	1330
	Preheater direct-fired	70	25	970
	Precalciner direct-fired	100	25	1010
	Precalciner direct-fired	150	25	830
Mid-kiln Firing	Long wet	30	25	550
	Long wet	50	25	430
	Long dry	25	25	610
	Long dry	40	25	470
SNCR Urea-Based	Preheater	40	50	930
	Preheater	70	50	790
	Precalciner	100	50	880

	Precalciner	150	50	800
SNCR Ammonia-Based	Preheater	40	50	1110
	Preheater	70	50	910
	Precalciner	100	50	980
	Precalciner	150	50	880
SCR	Long wet	30	80	3600
	Long wet	50	80	3100
	Long dry	25	80	3630
	Long dry	40	80	3170
	Preheater	40	80	4120
	Preheater	70	80	3490
	Precalciner	100	80	4870
	Precalciner	150	80	4400

4.5.2.2 OTHER REFERENCES

1) USEPA, "Finding of Significant Contribution and rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone; Rule", 63 FR 57356, October 27, 1998.
2) *State of Michigan* v. *U.S. Environmental Protection Agency*, 213 F.3d 663 (D.C. Cir. 2000).
3) Alternative Control Techniques Document-NOx Emissions from Cement Manufacturing. EPA-453/R-94-004, March 1994, USEPA, Research Triangle Park, North Carolina 27711
4) Section 11.6, Portland Cement Manufacturing, (revised January 1995) AP-42, Compilation of Air Emission Factors Volume 1: Stationary Point and Area Source. Office of Air Quality Planning and Standards, USEPA, Research Triangle Park, North Carolina 27711
5) USEPA "Regulatory Impact Analysis for the NOx SIP Call, FIP, and Section 126 Petition, Volume 1: Costs and Economic Impact", EPA-452/R-98-003, September 1998, USEPA, Office of Air and Radiation, Washington, DC 20460
6) USEPA, "Federal Implementation Plans to Reduce the Regional Transport of Ozone; Proposed Rule", 63 FR 56394, October 21, 1998.

5. Lime Kilns

5.1 Introduction

Lime is produced only in rotary kilns in Illinois, even though other types of lime kilns are available in the market. The kilns are very similar and the process is very similar to that of cement kilns. The most significant difference with regard to NOx emissions is that the firing temperature for lime kilns does not need to be as high as for cement kilns. Therefore, the contribution of thermal NOx is less. The emissions levels of Table 5-1 are proposed emission rates for lime kilns located in the Chicago NAA and Metro-East NAA that have NOx emissions of 15 tons per year or more and 5 tons or more during the ozone season.

Table 5-1. Proposed emission levels for affected Lime Kilns

Fuel	Lb/ton of lime produced
Gas	2.2
Coal	2.5

5.2 Process Description and Sources of Emissions

5.2.1 Process Description

Lime is manufactured by high temperature calcination of either limestone or dolomite (also called dolomitic limestone). When limestone is used for calcination, it must contain at least 50 percent calcium carbonate. Dolomitic limestone contains a mixture of calcium carbonate and magnesium carbonate. Magnesium carbonate content is about 30 to 45 percent. Following reactions take place during calcination of limestone and dolomite:

$CaCO_3 + \text{heat} \rightarrow CO_2 + CaO$ (high calcium lime)
$CaCO_3.MgCO_3 + \text{heat} \rightarrow CO_2 + CaO.MgO$ (dolomitic lime)

The theoretical temperature required for calcination is about 1650°F (900°C). However, in practice, calcination is carried out at a much higher temperature depending on the type of kiln used. A rotary kiln is the most commonly used kiln and it accounts for about 90 percent production of lime nationwide. In Illinois, lime production is carried out only in rotary kilns.

Since calcination is carried out only in rotary kilns in Illinois, operation of this kiln is discussed in a little more detail below.

Rotary Kiln

The rotary kilns used in lime calcination are very similar to those used in the cement industry. The main difference is that the firing temperature does not need to be quite as high for lime calcinations as for cement production. Feed, of course is different as well. Limestone, dolomite, or both are the principal feedstock along with fuel.

Calcination temperature lies somewhere between 900 and 1500°C (1650 and 2730°F). A typical calcination temperature is about 2460°F (1,350°C). Calcination temperature depends on the limestone feed size, final product quality, as well as type of fuel used. When calcination is carried out at 2460°F, hot lime comes out of the kiln at about 2200°F (1204°C). Most heat transfer in the calcining zone is by radiation.

The minimum heat requirement to convert 100 percent pure calcium carbonate to lime is about 3.0 million Btu/ton of quicklime or about 5.4 million Btu/ton of limestone. For simple gas fired kilns, heat usage can be as high as 9200 MJ/metric ton (8.7 million Btu/ton) of quicklime, and for coal-fired kilns, heat usage as can be as high as 7500 MJ/metric ton (6.5 million Btu/ton).

Preheater Rotary Kiln

Like cement kilns, older lime kilns do not have preheaters. Similar to cement kilns, modern lime kilns are fitted with preheaters and are generally much shorter than the conventional rotary kilns. The length of a preheater kiln ranges from 130 feet to 300 feet. The heat use – and therefore the NOx formation – is reduced in a preheater kiln due to the much more efficient heating and less combustion needed.

5.2.2 Sources of NOx Emissions

This section covers how NOx is formed during the combustion of fuel in the air, factors that affect emissions of nitrogen oxides emissions.

The manufacture of lime involves high process temperatures which are favorable for NOx formation. Essentially all of the NOx is formed in the lime kiln. Although, there are other heating operations, such as drying of raw feed or coal, often the heat from the kiln exhaust is used for these operations making their contributions to NOx emissions negligible.

5.2.3 Factors Affecting Uncontrolled NOx Emissions

NOx is formed in the primary burn zone, which is in the rotary section of the kiln. NOx may also be formed in the preheater section, where fuel may be added and burned.

5.2.4 NOx Formation in the Kiln Burning Zone

Even in preheater kilns, most of the NOx is formed in the primary kiln burning zone where most of the heat is added and the highest temperatures are experienced. Many of the same factors that impact NOx formation in cement kilns also impact NOx formation in lime kilns. Like cement kilns, most lime kilns were originally built as direct fired systems. Therefore, they are not generally equipped with low NOx burners. Lime kilns do have somewhat different process conditions – often somewhat lower burn temperatures – so NOx emissions will be somewhat different. For example, due to the somewhat lower temperature in a lime kiln, the contribution of thermal NOx to total NOx may be less than in a cement kiln.

Process conditions such as temperature stability, size of limestone feed, and moisture content can also have a significant impact on NOx emissions. The heating value of the fuel burned may also affect NOx emissions. High heating value fuels, such as petroleum coke, require less combustion air and produce less NOx per ton of limestone.

5.2.5 Suspension Preheater Kilns with Riser Duct Firing

As discussed earlier, preheater kilns are more energy efficient than kilns without preheaters. About 10-20 percent of fuel is fired into the riser duct. Because of higher energy efficiency and reduction in the amount of fuel burned at the higher lime burning temperature, NOx emissions from preheater kilns are lower as compared to the long dry kilns. Burning of coarse fuels (such as tires) into the kiln riser duct may further reduce NOx emissions from the kilns. The effectiveness of this method will vary somewhat from kiln to kiln.

5.3 Baseline or Uncontrolled NOx Emissions

Baseline NOx emissions are strongly influenced by kiln design, fuel characteristics, peak flame temperature, and oxygen concentration. The NOx emission data of Table 5-2 is shown for lime kilns based on AP-42.

Table 5-2: NOx Emission Factors for Different Kiln Types

Lime Kiln Type	SCC #	NOx Emissions (lb/Ton Lime)	Source
Coal-Fired Rotary Kiln	30501618	3.1	AP-42, Table 11.17-6
Gas-Fired Rotary Kiln	30501619	3.5	AP-42, Table 11.17-6
Coal and Gas-Fired Rotary Kiln w/water scrubber	30501620	2.7	AP-42, Table 11.17-6
Gas-Fired Calcimatic Kiln	30501605	0.15	AP-42, Table 11.17-6
Gas-Fired Parallel Flow Regenerative Kiln w/ Fabric Filter	30501623	0.24	AP-42, Table 11.17-6

For our purpose, we will restrict our control technology discussion only to rotary kilns as they are the only one used in lime production in Illinois.

5.4 Technical Feasibility of NOx Controls

For any given type of the lime kiln, energy consumption in the lime-making process directly influences the amount of NOx formed. Thus, the measures that improve the energy efficiency of this process should reduce NOx emissions in terms of pounds ("lb") of NOx per ton of product.

Since rotary lime kilns are similar to rotary cement kilns, NOx controls applicable to cement kilns are generally applicable to lime kilns, while the amount of NOx reduction will vary somewhat due to the different process conditions. NOx control approaches applicable to the lime industry may be grouped into two categories:

- Combustion control approaches where the emphasis is on reducing NOx formation, and
- Post-combustion control approaches which destroy the NOx formed in the combustion process.

5.4.1 Combustion Controls

5.4.1.1 Combustion Zone Control of Temperature and Excess Air

NOx emissions from a lime kiln are mainly a function of temperature and the amount of nitrogen and oxygen that can react together. Because the high temperature needed to convert the raw materials into lime is very conducive to NOx formation, significant NOx reductions can be obtained by lowering kiln operating temperatures, and by lowering the excess air ratio thus decreasing the amounts of nitrogen and oxygen available for reacting. On the other hand, a minimum operating temperature is necessary to maintain the quality of the lime that is being produced.

The solution to NOx via combustion zone control of temperature and excess air is therefore to determine the minimum excess air ratio necessary for product quality, to maintain this ratio by continuously monitoring oxygen and carbon monoxide levels in the exhaust, and to keep the temperature low by also continuously monitoring NOx in order to also maintain low NOx concentrations. This can be achieved by a monitoring feedback control system for excess air. According to the ACT for cement kilns, combustion zone control of temperature and excess air can provide approximately a 15% reduction of NOx from a cement kiln. Similar reduction would be expected from lime kilns.

5.4.1.2 Changing Kiln Fuel

Coal and natural gas are the most commonly used fuels for lime kilns in the United States. Although coal contains considerable nitrogen, and natural gas is virtually nitrogen free, NOx emissions from kilns burning natural gas tend to be somewhat higher than the emissions from kilns burning coal because in kiln conditions natural gas flames are considerably hotter than coal flames. However, as shown in Table 5-2, combined gas and coal flames can potentially produce lower NOx.

5.4.1.3 Staging of Combustion

Like cement kilns, NOx can be reduced by staging combustion. The following approaches, which are used in cement kilns and are described in the previous chapter, can also be used in lime kilns.

- Staging Combustion by Use of Indirect Firing
- Staging Combustion by Flue Gas Recirculation
- Staging Combustion with Low NOx Burners
- Staging Combustion by Mid-Kiln Firing

Due to slightly different process conditions – mainly firing temperature – performance may be somewhat different.

5.4.2 Post-Combustion Control of NOx Emissions

Like cement kilns, there are two forms of post combustion controls that may be employed in lime kilns, they are:

- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)

5.4.2.1 Selective Catalytic Reduction (SCR)

SCR would generally be the most costly technology to employ, but would also result in the highest reduction in NOx emissions. It is expected the companies operating lime kilns will find less expensive ways to reduce NOx and comply with the proposed rule than use of SCR.

5.4.2.2 Selective Non-catalytic Reduction (SNCR)

SNCR is a less costly method of NOx control than SCR and would face the same issues regarding application as for cement kilns. Generally, gas in the correct temperature range for SNCR is more likely to be accessible with a preheater kiln than a simple rotary kiln without a preheater.

Table 5-3 summarizes the NOx emissions reductions potential of various control strategies for lime kilns. This information is consistent with AirControlNet.

Table 5-3: NOx Emissions Reduction from Rotary Lime Kilns with Various NOx Control Technologies

NOx Control Technology	Expected NOx Emissions Reduction (%)	Expected Controlled NOx, lb/ton	
		Coal-Fired	Gas-Fired
Low - NOx Burner	30	2.17	2.45
Mid - Kiln Firing	30	2.17	2.45
SNCR-Urea	50	1.55	1.75
SNCR-Ammonia	50	1.55	1.75
SCR	80	0.62	0.7

5.5 Cost Effectiveness of NOx Controls

Cost effectiveness estimates performed by Illinois EPA using AirControlNet (cost year 1992) are shown in Table 5-4. These are very consistent with independent estimates performed by USEPA staff and shown in Tables 5-5 and 5-6. In the case of Table 5-5, USEPA estimated ozone season cost in $/ton and Andover Technology Partners estimated the annual cost in $/ton as indicated in the table.

Table 5-4: Cost Effectiveness of Various Control Options for Rotary Lime Kilns (Source: AirControlNet. Cost Year 1992)

NOx Control Technology	Expected NOx Reduction, %	Controlled NOx lb/ton quicklime	Cost Effectiveness, $/Ton NOx Removed
Low - NOx Burner	30	2.17 (Coal) 2.45 (Gas)	560
Mid - Kiln Firing	30	2.17 (Coal) 2.45 (Gas)	460
SNCR-Urea	50	1.55 (Coal) 1.75 (Gas)	770
SNCR- Ammonia	50	1.55 (Coal) 1.75 (Gas)	850
SCR	80	0.62(Coal) 0.7 (Gas)	3370

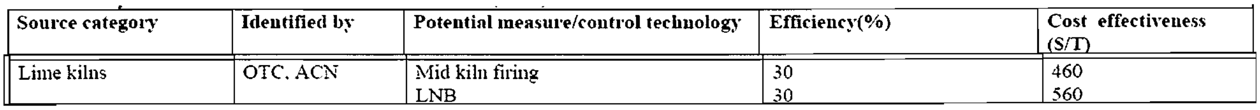
* The data is from the ACT document for cement kilns. The same data has been used by the Texas Board in its analysis.

Table 5-5 Estimates From USEPA - 1999
USEPA, Nitrogen Oxides (NOx) Why and How They Are Controlled, Reference: EPA-456/F-99-006R, November 1999, http://www.epa.gov/ttn/catc/dir1/fnoxdoc.pdf

		% Reduction	Ozone Season $/ton	Est. Annual $/ton*
Lime Kilns	Mid-Kiln Firing	30	1,110	460
Lime Kilns	LNB	30	1,340	560
Lime Kilns	SNCR - Urea Based	50	1,280	770**
Lime Kilns	SNCR - NH3 Based	50	1,490	800**
Lime Kilns	SCR	80	6,850	2970**

*estimated from Ozone Season estimate. Capital cost contribution of ozone season cost multiplied by 5/12
** assumes $300/ton operating cost for NH3 SNCR and $400/ton of NOx operating cost for urea SNCR and $200/ton of NOx for SCR

Table 5-6. Cost Estimates from USEPA - 2006
8/21/06 -- Bill Neuffer, USEPA
http://www.epa.gov/groundlevelozone/SIPToolkit/documents/stationary_nox_list.pdf



Source category	Identified by	Potential measure/control technology	Efficiency(%)	Cost effectiveness (S/T)
Lime kilns	OTC, ACN	Mid kiln firing LNB	30 30	460 560

6. Reheat, Annealing and Galvanizing Furnaces at Iron/Steel plants

6.1 Introduction

The purpose of this section is to provide a brief description of furnaces used in iron and steel plants, the sources of NOx emissions, the baseline NOx emissions, the factors affecting baseline NOx emissions, the available NOx control technologies, and the estimated costs of controls. Table 6-1 shows emission levels that are proposed for reheat, annealing and galvanizing furnaces located in the Chicago NAA and Metro-East NAA that have NOx emissions of 15 tons per year or more and 5 tons or more during the ozone season.

Table 6-1. Proposed Emission Levels for Reheat, Annealing and Galvanizing Furnaces

type	Limit (lb/MMBtu)
Reheat furnace, regenerative	0.18
Reheat furnace, recuperative	0.05
Reheat furnace, cold air	0.03
Annealing furnace regenerative	0.38
Annealing furnace, recuperative	0.16
Annealing furnace, cold air	0.07
Galvanizing furnace, regenerative	0.46
Galvanizing furnace, recuperative	0.16
Galvanizing furnace, cold air	0.06

6.2 Process Description and Sources of Emissions

6.2.1 Process Description

Reheat, annealing, and galvanizing furnaces are used in integrated iron and steel plants where steel is produced by reduction of iron ore in a blast furnace. The pig iron that is produced is then processed in a basic oxygen furnace to remove carbon and other impurities. If iron ore is directly reduced by a direct reduction process, it is sent either to a basic oxygen furnace or an electric arc furnace for further purification. Molten steel from either a basic oxygen furnace or electric arc furnace is typically processed through a continuous caster where it is shaped into slabs, billets, or blooms. Alternatively, the molten iron can be cast into ingots and stored for subsequent processing.

Slabs, billets, and blooms from continuous caster are typically reheated to a suitable working temperature in a reheat furnace prior to further shaping. Ingots are typically heated in soaking pits prior to further processing. Reheat furnaces and soaking pits are high temperature, fossil fuel burning furnaces and are sources of NOx emissions.

After steel comes out of a reheat furnace or soaking pit, it is further processed in annealing and galvanizing furnaces. These finishing operations are conducted at suitable temperatures and are also sources of NOx emissions.

Reheat, annealing, and galvanizing furnaces are also used in mini mills and specialty steel producing plants. Typically, they receive scrap iron or iron produced at primary iron and steel facilities. The operations of these furnaces are similar to those at primary iron and steel plants.

Reheat furnaces bring steel to a uniform temperature of about 2150 to 2450°F, a temperature suitable for hot working. These furnaces are designed to accommodate the steel being processed at a suitable rate, heat it uniformly, and hold it at a desired temperature for a specified length of time. These furnaces may be batch-type or continuous-type. In a continuous reheat furnace, there may be some variations on how the charge moves through it. The variations include roller hearth furnaces in which the charge moves over the rollers, walking beam furnaces in which material is moved in a controlled step-wise manner, pusher-type furnaces in which a continuous line of material is pushed over skids, and rotary hearth furnaces with cellular hearths that rotate in a horizontal plane. Other variations include the introduction and removal of charge and circulation of heat. Circulation of heat is accomplished by natural convection and stack drift.

The sizes of reheat furnaces vary. Large reheat furnaces can have a hearth area up to 4000 square feet. The capacity of a reheat furnace is determined by the surface area of the material to be heated, the shape, thickness, and composition of the material, and the temperature of the material and the furnace.

Reheat furnaces may use preheated combustion air or ambient combustion air. Furnaces using preheated combustion air are equipped with regenerative or recuperative systems to recover heat from the exhaust gases to improve thermal efficiency. Improved thermal efficiency will generally reduce total NOx emissions (but, not necessarily emission rates in lb/MMBtu) since heat input per unit output is reduced.

Flat-rolled steel products such as coils of sheets are sometimes annealed to enhance some physical properties of the product. It is carried out by subjecting steel to a carefully controlled thermal cycle to relieve stresses induced by hot and cold working. Only cold-rolled steel coils are annealed, as hot rolled coils are self-annealed. Annealing is generally done at about 1250°F. Sometimes higher temperatures may be used for annealing. Annealing may be carried out continuously or in a batch-type furnace.

Galvanizing or coating with zinc, aluminum, or other alloys is done to protect steel from corrosion. At iron and steel mills, steel sheets, strips, and other products with a light cross section are typically galvanized. A typical molten zinc bath temperature is 850°F, requiring a heat source. Precise temperature control is very important in galvanizing furnaces.

Some galvanizing furnaces employ the use of direct flame impingement (DFI) oxy-fuel technology. DFI implies that the oxy-fuel flame is in direct contact with the object to be heated. This drastically increases the heat transfer and when employed in certain existing furnaces it can result in 50% more throughput capacity.

Both annealing and galvanizing processes can be done in a single continuous facility that includes a continuous annealing furnace followed by a continuous sheet galvanizing furnace. Because of lower temperatures used in both annealing as well as galvanizing processes when compared to reheat furnaces, NOx emissions from these processes tend to be lower as compared to those from reheat furnaces.

In both annealing and galvanizing furnaces, preheated combustion air may be used. Preheating of air can be carried out in recuperators or regenerators to improve thermal efficiency.

6.2.2 NOx Formation and Sources of NOx Emissions

This section covers how NOx is formed during the combustion of fuel in the air, factors that affect emissions of nitrogen oxides emissions, and provides a summary of uncontrolled or baseline NOx emissions from reheat, annealing, and galvanizing furnaces.

6.2.3 NOx Formation

Reheat, annealing, and galvanizing furnaces tend to use gaseous fuels, i.e. natural gas, coke oven gas (COG), and blast furnace gas (BFG) for heating metal. These fuels contain very small amounts of fuel nitrogen and hence most of NOx formed is thermal NOx. This is formed when nitrogen present in the air combines with oxygen in the air. Prompt NOx, which generally is formed when atmospheric oxygen reacts with hydrocarbon radicals derived from fuel, is not a major factor. Nitrogen oxides emissions from fired processes are typically 90-95% NO with the balance NO_2. However once the flue gas leaves the stack, NO is eventually oxidized to NO_2.

6.2.4 Baseline or Uncontrolled NOx Emissions

Baseline NOx emissions are strongly influenced by furnace type, fuel characteristics, peak flame temperature, and oxygen concentration. The NOx emissions data are available in the ACT document for reheat, annealing, and galvanizing furnaces at iron and steel plants. Table 6-2 presents uncontrolled NOx emissions data for these sources.

Table 6-2: Baseline NOx Emissions for Reheat, Annealing, and Galvanizing Furnaces

Source: Table 2-1, ACT

Furnace Type	**Source Type**	**Baseline NOx Emissions ppm @ 3 O_2**	**Baseline NOx Emissions Lb/mmBtu**
Reheat Furnaces	Regenerative	650	0.79
	Recuperative	220	0.20
	Cold-Air	120	0.14
Annealing Furnaces	Regenerative	780	1.15
	Recuperative	330	0.40
	Cold-Air	120	0.14
Galvanizing Furnaces	Regenerative	9240	1.2
	Recuperative	330	0.40
	Cold-Air	120	0.14

6.3 Technical Feasibility of NOx Controls

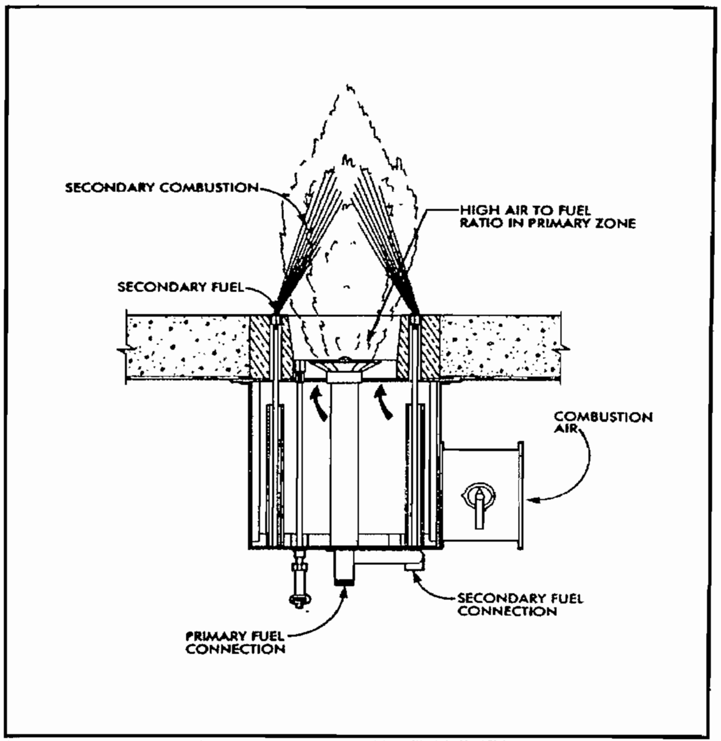
In its document, Alternative Control Techniques Document--NOx Emissions from Iron and Steel Mills, EPA-453/R-94-065 ("ACT"), October 1995, USEPA has identified control techniques for reheat, annealing, and galvanizing furnaces. NOx control approaches applicable to these furnaces may be grouped into two categories:

- Combustion control approaches where the emphasis is on reducing NOx formation, and
- Post-combustion control approaches which destroy the NOx formed in the combustion process.

Combustion controls such as low NOx burners (LNB) and flue gas recirculation (FGR) fit into the first category. Sometime FGR is incorporated into their low NOx burner design. Add-on flue gas treatment controls such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) are examples of the second. Wherever practicable, combustion control techniques should be used as they are generally cheaper compared to post combustion controls.

6.3.1 Combustion Controls

Figure 6-1. Example of a staged fuel burner.[30]



Several combustion control techniques are available for NOx emissions from reheat, annealing, and galvanizing furnaces. They include low excess air (LEA), LNB, FGR, or a combination of these techniques. By limiting the amount of excess air and by lowering flame temperature, NOx emissions can be reduced from these furnaces.

Low NOx Burners

LNB employ a variety of principles including LEA, staged combustion, and FGR. LNB may be staged air burners or staged fuel burners. Staged air burners are designed to reduce turbulence, delay fuel/air mixing, and establish fuel-rich zone for initial combustion. The reduced availability of oxygen in the initial or primary combustion zone inhibits fuel NOx conversion. During the second stage, partially combusted gases mix with excess air to complete combustion process. The longer, less intense flames resulting from air staging leads to lower peak flame temperatures and reduced thermal NOx formation.

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[30] Waible, R., Price, D., Tish, P., Halpern, M., “ADVANCED BURNER TECHNOLOGY FOR STRINGENT NOx REGULATIONS”, American Petroleum Institute Midyear Refining Meeting, Orlando, FL, May 8, 1990

Staged fuel burners mix a portion of the fuel and all of the air in the primary combustion zone. The high level of excess air greatly lowers the peak flame temperature which results in reduced amount of thermal NOx formation. The secondary fuel is injected at high pressure into the combustion zone through a series of nozzles that are positioned around the periphery of the burner, as shown in Figure 6-1. This results in rapid mixing of fuel gas with furnace gases. Staged fuel burners produce compact flames.

Some burner designs include FGR within the burner. FGR may also be external, which requires additional ductwork and fans, increasing cost. Either way, FGR enhances NOx reduction of LNB.

LNB can reduce NOx emissions by 40 to 60 percent. This technology has been applied in reheat, annealing, and galvanizing furnaces in the United States.

Low NOx Burner plus Flue Gas Recirculation

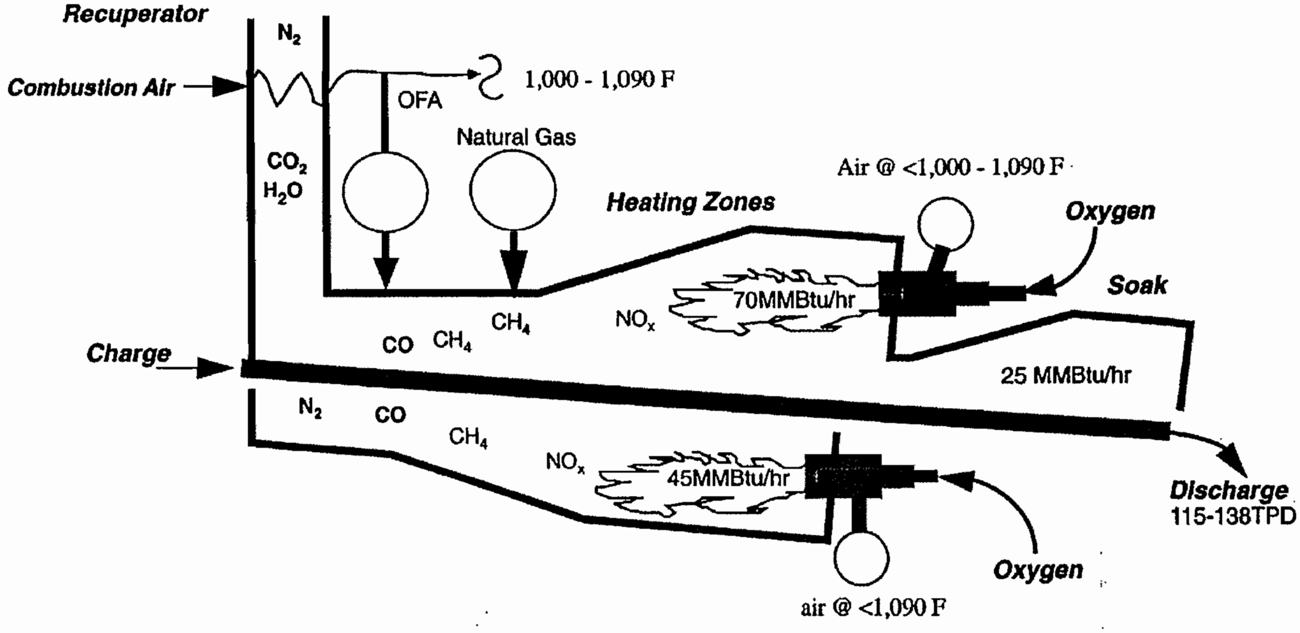
As discussed earlier, some LNB incorporate flue gas recirculation (FGR) in the burner itself. In some furnaces, external FGR is added to enhance NOx reduction. Flue gas recirculation is implemented by recycling a portion of the flue gas to the primary combustion zone. Since flue gas contains lower concentration of oxygen, its injection dilutes the overall oxygen concentration at the primary combustion zone, which results in lower peak flame temperature, and hence lower amount of thermal NOx formation.

Flue gas recirculation has been applied to reheat, annealing, and galvanizing furnaces with LNB.

Gas Reburn

Gas Reburn is a form of fuel staging that reduces the NOx formed in the primary burn zone. Gas reburn may be applied to reheat furnaces. Concerns relate to potential increases in fuel consumption as well as increases in furnace exit temperature. Gas reburn may be combined with oxygen-enriched combustion, as shown in Figure 6-2. Oxygen enrichment can increase NOx emissions, but also heat flux. Gas reburn can be used to reduce NOx emissions – regardless of whether oxygen enrichment is used. Pilot tests showed that reburn could reduce NOx by up to 73%.

Figure 6-2. Natural Gas Reburning with Oxygen Enriched burners.
Advanced Steel Reheat Research and Development, Final Report, DOE/ER/12200—T2
http://www.osti.gov/energycitations/servlets/purl/362534-YnV6gu/webviewable/



6.3.2 Post-Combustion Control of NOx Emissions

Post-Combustion Control Technologies that may be used on reheating, annealing or galvanizing furnaces include:

- Selective Catalytic Reduction (SCR), and
- Selective Non-Catalytic Reduction (SNCR)

Selective Catalytic Reduction

SCR is the most advanced of the flue gas treatment methods for reducing NOx emissions. SCR can reduce NOx emissions by 80 to 90 percent and even higher. However, SCR entails higher costs than other methods of control due to the capital cost. Some Nucor facilities in the United States control NOx emissions by the use of SCR alone or by a combination of SNCR and SCR using an aqueous urea solution. NOx reductions of about 78-86% have been realized. (Source: http://www.icac.com/Files/Rowlan.pdf). Although SCR is a technology that may be employed, it is not likely to be employed for compliance with the proposed rule because other, less costly, technologies are available to achieve the NOx emission reductions of this rule.

Selective Non-Catalytic Reduction (SNCR)

SNCR accomplishes the same chemical reactions as SCR in order to reduce NOx to nitrogen. It avoids the high costs of SCR but requires high temperatures in order to compensate for the lack of catalyst and to prevent emissions of unreacted ammonia. Too high temperatures, however, cause ammonia to significantly participate in a competing reaction that can actually form more NOx.

The temperature "window" for effective SNCR is 1600 to 2200°F. Generally, 40 to 70 percent NOx reduction is achieved with NH3 to NOx molar ratio of 1:1 to 2:1. The wide range of molar ratio is because of the difficulty of achieving uniform mixing of ammonia with flue gas and because of variations of flue gas temperature and composition usually present.

Table 6-3 summarizes the NOx emissions reductions potential of various control strategies for furnaces.

Table 6-3: Expected NOx Emissions Reduction with NOx Control Technologies
Ref.: Table 2-2, Page 2-8, ACT

Furnace Type	Control	NOx Emissions lb/mmBtu			Percent NOx Reduction
		Regenerative	Recuperative	Cold-Air	
Reheat	LEA	0.69	0.17	0.12	13
	LNB	0.27	0.068	0.046	66
	LNB+FGR	0.18	0.046	0.031	77
Annealing	LNB	0.48	0.20	0.07	50
	LNB+FGR	0.38	0.16	0.07	60
	SNCR	0.38	0.16	0.07	60
	SCR	0.14	0.06	0.02	85
	LNB+SNCR	0.19	0.08	0.03	80
	LNB+SCR	0.095	0.04	0.015	90
Galvanizing	LNB	0.57	0.20	0.07	50
	LNB+FGR	0.46	0.16	0.06	60

Combinations of SCR and SNCR have been employed. For example, as shown in Appendix C-1, Fuel Tech has supplied combined SNCR and SCR systems to provide on the order of 70-80% NOx reduction from a number of steel facilities. The advantage of the combined approach is that it enables a much smaller SCR to be used, which reduces the capital cost of the system.

6.4 Cost Effectiveness of NOx Controls

The USEPA and others have prepared a number of cost effectiveness estimates for controlling NOx emissions from reheat, annealing, and galvanizing furnaces. Two significant estimates are contained in the federal ACT for iron and steel plants and AirControlNet. The Illinois EPA is relying on these and other supporting documents to estimate the cost effectiveness of controlling Illinois NOx sources to the level proposed by this rulemaking.

Figure 6-3. Cost Effectiveness of Combustion Controls

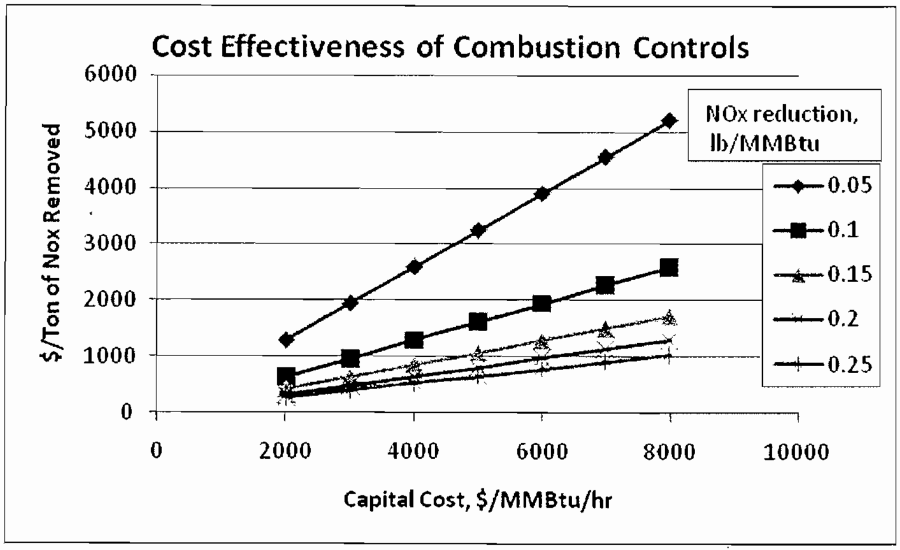


Figure 6-3 is identical to Figure 3-7 of this document, and is a generic estimate of cost effectiveness (in $/ton of NOx removed) for combustion controls. Intrinsic to the estimates in thisfigure are that the facility operates 8000 hours per year and that there are no additional operating costs. Lower operating hours would entail higher costs. The assumption of no additional operating costs is reasonable, especially for any application without external FGR. Since $5000/MMBtu/hr is toward the high end of the capital cost of combustion controls, for the levels of NOx reduction envisioned in most cases, costs in $/ton of NOx are typically under $1000/ton. This is consistent with the results of calculations by USEPA in 2006 shown in Table 6-4.

Table 6-4. Cost Estimates from USEPA - 2006
8/21/06 -- Bill Neuffer, USEPA
http://www.epa.gov/groundlevelozone/SIPToolkit/documents/stationary_nox_list.pdf

Source category	Identified by	Potential measure/control technology	Efficiency(%)	Cost effectiveness (S/T)
Iron/steel mills Annealing furnaces	STAPPA, ACN	SNCR	60	1,600
		LNB	50	570
		LNB + FGR	60	750
		LNB + SCR	80	1,700
Galvanizing furnaces		LNB + FGR	60	580
		LNB	50	490
Reheating furnaces		LNB + FGR	77	380
		LNB	50	490

6.4.1 ACT Cost Effectiveness

Three cost considerations are presented in the federal ACT document: total capital costs, total annual costs, and cost effectiveness. The total capital cost is the sum of the purchased equipment costs, direct installation costs, indirect installation costs, and contingency costs. Annual costs consist of the direct operating costs of materials and labor for maintenance, operation, utilities, and material replacement and disposal and indirect operating charges including plant overhead, general administration, and capital recovery charges. Cost effectiveness, in dollars/ton of NOx removed, is calculated for each control technique by dividing the total annual cost by the annual tons of NOx removed.

The ACT describes the costs of various NOx controls applicable to reheat, annealing, and galvanizing furnaces. Depending on the type of the furnace, the cost effectiveness of each control varies from a few hundred to several thousands dollars per ton of NOx removed. Low excess air (LEA) is shown to be very costly on a $/ton basis. However, it should be kept in mind that the actual cost is low while the reduction is also very low. The high $/ton value associated with LEA results from the very low NOx reduction possible from LEA.

Table 6-5 summarizes the cost effectiveness of various control options for reheat, annealing, and galvanizing furnaces used at iron and steel plants.

Table 6-5: Cost Effectiveness of Various NOx Control Technologies for Reheat, Annealing, and Galvanizing Furnaces
Source: ACT

Furnace Type	Control	Furnace Size mmBtu/hr	Cost Effectiveness, $/Ton NOx Removed		
			Regenerative	Recuperative	Cold-Air
Reheat	LEA	140	550	2100	3200
	LNB		130	510	760
	LNB+FGR		160	620	930
	LEA	300	410	1600	2400
	LNB		90	350	400
	LNB+FGR		110	460	690
	LEA	520	330	1300	1900
	LNB		70	260	390
	LNB+FGR		90	340	500
Annealing	LNB+FGR	100	320	750	1900
	SNCR		650	1500	3800
	SCR		1700	4200	11000
	LNB+SNCR		670	1700	5000
	LNB+SCR		1800	4300	12000
	LNB	200	200	480	1300
	LNB+FGR		260	580	1600
	SNCR		580	1300	3700
	SCR		1200	2900	7200
	LNB+SNCR		570	1100	3400
	LNB+SCR		1300	3100	7900
	LNB+FGR	300	210	490	1500
	SNCR		540	1200	3700
	SCR		1100	2500	6900
	LNB+SNCR		520	1200	3400
	LNB+SCR		1100	2600	7100

Galvanizing	LNB	50	190	530	1500
	LNB+FGR		230	640	2000
	LNB	100	110	320	900
	LNB+FGR		140	410	1200
	LNB	150	110	320	900
	LNB+FGR		140	400	1100

7. Glass Melting Furnaces

7.1 Introduction

The purpose of this section is to provide a brief description of glass melting furnaces, the sources of NOx emissions, the baseline NOx emissions, the factors affecting baseline NOx emissions, the available NOx control technologies, and the estimated costs of controls.

Under the proposed rule, glass melting furnaces located in the Chicago NAA and Metro-East NAA that have NOx emissions of 15 tons per year or more and 5 tons or more during the ozone season are subject to the numerical emission limits in Table 7-1.

Table 7-1. Proposed Numerical Emission Limits for Glass Melting Furnaces

Type	Lb/ton glass produced
Container Glass	5.0
Flat Glass	7.9
Other Glass	11.0

7.2 Process Description and Sources of Emissions

7.2.1 Process Description

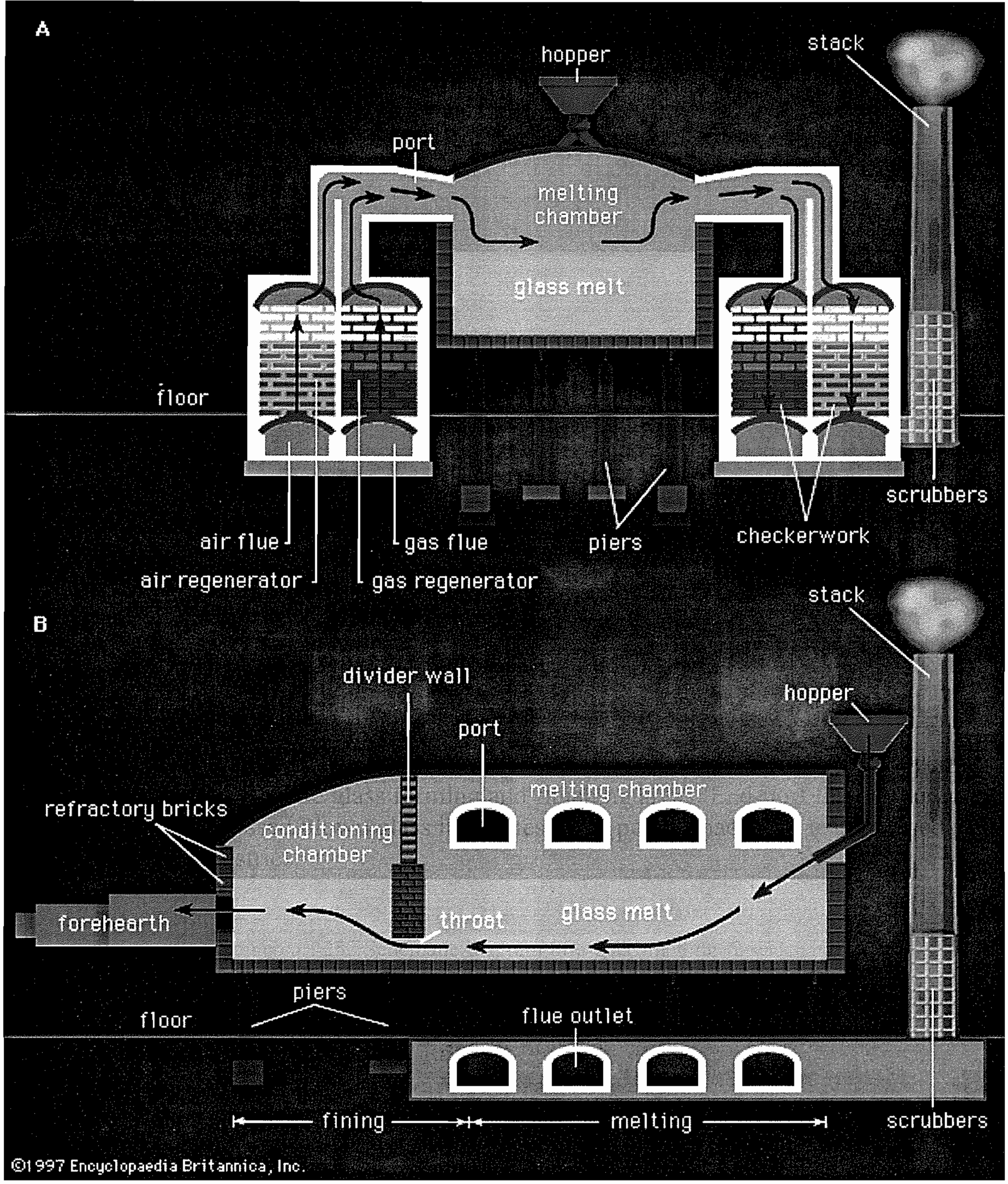
Glass melting furnaces are used in the production of flat glass, container glass, and other glass (which includes, among others, pressed and blown glass). Melting furnaces involved in the production of fiberglass are not included. Commercially produced glass can be classified as soda-lime, borosilicate, lead, and fused silica. Soda-lime glass is the most common type of glass produced by the glass melting furnaces.

Main raw materials for soda-lime glass production include soda ash, limestone, sand, and broken glass (called cullet). Other ingredients such as sodium and potassium nitrates, sodium sulfite, boric acid, lead etc. may be added to impart certain qualities to the glass. The first step in the production of glass is mixing of various ingredients in a batch mixer. The mixture is then fed in a semi-continuous way to one end of the melting furnace. In the melting furnace chemical reactions take place between the ingredients. The main reactions are as follows:

- $Na_2CO_3 + SiO_2 \rightarrow Na_2O.SiO_2 + CO_2$
- $CaCO_3 + SiO_2 \rightarrow CaO.SiO2 + CO_2$
- $Na_2SO_3 + SiO_2 \rightarrow Na_2O.SiO_2 + SO_2$

The heat for these chemical reactions is usually supplied by natural gas combustion in burners positioned over the melt. Heat is transferred by radiation from the flame to the surface of the melt. A furnace may have either side ports or end ports that connect brick checkers to the inside of the melter. Figure 7-1 shows a sideport furnace. The purpose of the brick checker is to conserve fuel by collecting furnace exhaust gas heat, so that when air flow is reversed, it is used to preheat the furnace combustion air. As a raw material mix enters the furnace through a feeder, it floats on the top of the melt. While it melts, it passes to the front of the melter and eventually flows out through a throat to the glass forming and finishing areas. End-port furnaces are usually used in container and pressed/blown glass industries. Side-port furnaces are usually used in flat and container glass industries.

Figure 7-1. Typical Sideport Glass Melting Furnace
http://www.britannica.com/eb/art-253/Schematic-diagram-of-a-glass-melting-furnace-showing-a-cross?articleTypeId=1



The combustion air preheat temperatures in flat glass furnaces can reach 2300°F and, because of that high temperature, a substantial amount of NOx may be formed in the checkers. Lower preheat is used in container glass furnaces and NOx formed in the checkers is usually small. In both the end-port and the side-port furnaces, the cycle of air flow from one checker to the other is reversed after about every 15-30 minutes. The end-port furnaces are usually smaller than side-port furnaces. For production of flat glass, more even heating is desired and side-ports are preferred for that. Production capacity of flat glass furnaces can be as large as 800 tons/day. The end-port furnaces are limited to about 175 tons/day capacity. Pressed and blown glass melting furnaces are usually the smallest, with production capacity of less than 50 tons/day.

Broken glass (cullet) is used both in container glass as well as flat glass manufacture. Cullet may be internally recycled glass produced at the plant in some downstream operations or may be externally recycled glass from glass recycled in recycle operations. Melting of cullet requires as much as half the energy used in melting of virgin ingredients used in the manufacture of glass. Use of external cullet is limited to container glass because of high quality requirements.

Glass can also be melted in all-electric furnaces and electric boost can be added to gas-fired furnaces. However, electric conductivity of the melt limits the size of the melting furnaces. Almost all electric melters are used in pressed and blown glass manufacture, though some are also used in container glass manufacture. Electric boost is common in container glass, but is not common in flat glass furnaces over 100 tons/day capacities.

Energy consumption for melting glass has declined over recent years because of advancement in better refractory materials. The fuel use for melting operations in the glass melting industries is approximately as follows:

Industry	Total Energy Consumed for melting (106 Btu/ton)
Container	8-10
Flat	6-7
Pressed/blown	16

7.2.2 NOx Formation and Sources of NOx Emissions

This section covers how NOx is formed during the combustion of fuel in the air, factors that affect emissions of nitrogen oxides emissions, and provides a summary of uncontrolled or baseline NOx emissions from various categories of glass melting furnaces.

Manufacture of glass involves high process temperatures which are favorable for NOx formation. Most of the NOx is formed in the melter, though some NOx is formed in the brick checkers depending on the temperature there. Because natural gas is used as a fuel in almost all glass melters, there is a little contribution of fuel NOx. Some glass raw materials contain nitrates (niter) which may emit NOx when heated. Uncontrolled NOx emissions depend primarily on various process parameters including fuel firing rate, furnace geometry, fuels and raw materials used. Therefore, uncontrolled NOx emissions can vary from site to site.

In glass melting furnaces, NOx is formed when nitrogen present in the air or fuel combines with oxygen in the air. The primary form of NOx is nitric oxide (NO) and is formed when atmospheric nitrogen combines with oxygen (thermal NOx). As discussed above there may be some NOx formed from the use of nitrates as feed material. Uncontrolled emissions of thermal NOx range from 8-10 lb NOx/ton glass produced.

7.2.3 Baseline or Uncontrolled NOx Emissions

Baseline NOx emissions are strongly influenced by furnace design, fuel characteristics, peak flame temperature, nitrogen and oxygen concentrations. The NOx emissions data are available in the ACT document for three types of glass melting furnaces, container glass, flat glass, and pressed/blown glass. Table 7-2 presents uncontrolled NOx emissions data for these furnaces. These values should be considered typical, with the understanding that there may be some variation about these values.

Table 7-2: NOx Emission Factors for Different Glass Melting Furnace Types

Glass Melting Furnace Type	Heat Input Requirement (mmBtu/Ton Glass)	Average NOx Emission Rate (lb/ton Glass)	Average NOx Emissions (lb/mmBtu Heat Input)
Container Glass	6.0	10	1.67
Flat Glass	6.0	15.8	2.63
Pressed/Blown Glass	6.0	22	3.67

As can be seen from Table 7-2, in general, pressed and blown glass produce highest NOx emissions of 22.0 lb NOx/ton of glass produced. If the furnace can be made more efficient without raising the emissions rate (in lb/MMBtu), then there can be a reduction in NOx.

7.3 Technical Feasibility of NOx Controls

In its document, Alternative Control Techniques Document--NOx Emissions from Glass Manufacturing, EPA-453/R-94-037 ("ACT"), June 1994, USEPA has identified control techniques in detail. NOx control approaches applicable to the glass melting industry may be grouped into three categories:

- Combustion modifications where the emphasis is on reducing NOx formation,
- Process modifications such as preheating of cullet, use of electric boost, and addition of feed nitrate (sodium nitrate), and
- Post-combustion control approaches which destroy the NOx formed in the combustion process.

In addition to NOx control techniques, several energy saving methods can reduce energy comsumption and hence reduce NOx emissions.

7.3.1 Combustion Modifications

Glass melting furnaces operate at very high combustion air temperatures and excess air levels compared to boilers. In addition, the glass furnaces use high-temperature refractory lined combustion chambers where NOx formation also occurs. These differences with the boilers result in high NOx emissions from glass melting furnaces.

All combustion modifications are designed to minimize NOx formation by any one or all of the following:

- reduce peak flame temperature
- reduce residence time in the flame zone
- reduce oxygen concentration in the flame zone
- reduce nitrogen in the combustion air

All these modifications can reduce NOx emissions, but for combustion with air reducing peak flame temperature has the greatest effect on thermal NOx emissions. Therefore, most combustion modifications focus on minimizing flame temperature.

Combustion modifications can be grouped as follows:

- Modification to the existing burner and burner hardware
  - low excess air operation
  - changing air/fuel contacting
- Modified burners

Many modifications which are good for boilers, such as fuel switching, water or steam injection, reduced air preheat, and derating are impractical for glass melting furnaces.

7.3.1.1 Modification to Existing Burners

Low Excess Air (LEA) Operation

LEA operation is routine in glass melting furnaces due to its effect on efficiency. LEA is designed to reduce the oxygen concentration in the flame zone, and thereby reduce NOx formation. Tests on a side-port and an end-port furnace show that LEA can reduce NOx emissions by 0-28 percent. (Reference: Table 5-1, page 5-33, ACT). As a result, LEA can produce some NOx reductions; but, it is not a method for large reductions in NOx emissions.

Changing Air/Fuel Contacting

Regenerative furnaces are generally fired by mixing a horizontal stream of preheated combustion air with a stream of natural gas fuel injected in a much smaller separate port at an angle. In most regenerative furnaces, natural gas is introduced into the furnace through a port just under the combustion air port. This type of firing is called under-port firing. In over-port firing, natural gas is introduced above the combustion air port, and in the side-port firing, natural gas is introduced at the same level as the combustion air. Both over-port as well as side-port firings are also practiced in glass melting furnaces. The mixing of fuel with air is accomplished by injecting fuel at a high velocity (typically 500-800 feet/second) and air at a much lower velocity (about 20-30 feet/second).

By changing gas and air velocities, contact angle between the gas and combustion air and location of natural gas injection (e.g. from under-port to over-port), it may be possible to change primary variables, such as flame temperature, oxygen concentration, and gas residence time at peak flame temperature that influence NOx formation. In reality, however, changing these design features in an existing furnace might be difficult.
(Reference: Page 5-42, ACT)

It has been shown that decreasing fuel injection velocity lowers NOx concentration for a wide range of contact angles, port configuration, and burner types. It has also been shown that high combustion air velocity in relatively short ports in the side-port furnaces cause more gas mixing and higher peak flame temperatures that lead to higher NOx emissions than in the end-port furnaces. It has also been shown that by reducing contact angle, gas mixing can be reduced which also leads to lower NOx emissions. (Reference: page 5-48, ACT)

Another type of burner uses methane dissociation and slight oxygen enrichment (20.9 percent to 21.6 percent) to increase flame luminosity in glass furnaces. This increase in luminosity increases heat transfer from the flame to melt, lowering energy requirements, and decreasing NOx emissions (lb/ton of glass). One test claims a 35 percent reduction in NOx emissions and 6 percent savings in fuel usage. (Reference: page 5-50, ACT).

Fuel Switching or Co-firing

Because oil has a more luminous flame, which enhances radiant heat transfer, flame temperature is reduced for oil. This permits oil flames to produce lower NOx despite having a higher fuel nitrogen level. Therefore, one option for reducing NOx is through burning some oil in the furnace. The capital cost of switching will generally be low and there may be an operating cost, depending upon the differential in fuel costs.

Modified Burners

Low NOx burners (LNB) have been used widely in boilers and process heaters. They are designed to stage the combustion process in several distinct zones. In a two-stage LNB, combustion is fuel rich in the first stage and air rich in the second. The purpose is to minimize the peak flame temperature and corresponding oxygen concentration which help in minimizing NOx emissions. LNB can also be designed to improve fuel efficiency. NOx reduction of about 30-50 percent is possible with these burners. More recent LNB allow adjustment of air/fuel velocities, contact angle, flame shape, and injection orifice. These features can further improve LNB performance.

Some LNB can achieve NOx reduction by as much as 60 percent from the uncontrolled levels by a combination of furnace and burner block sealing to limit air infiltration. Tests conducted in 1991 on Sorg burner (Cascade™ burner) installed on two container glass melting furnaces with under-port firing showed that NOx can be reduced by about 40-60 percent. Since under-port firing is not typically used in a flat glass furnace, the burner has not been tested on flat glass melting furnaces. No information is available on the applicability of this burner on pressed/blown glass furnaces.
(Reference: Table 5-3, pages 5-57 and 5-60, ACT)

The Korting burner, developed by a German firm, incorporates orifice sealing (to prevent in-leakage of air) and flue gas recirculation in their LNB. This "staged-air" burner injects additional air into the end of the furnace outside of the burners for completion of combustion. Introduction of natural gas through a jet nozzle causes atmospheric air to be sucked in by vacuum. Control of primary air at the burner tip allows enough air so that partial combustion of the gas takes place between 1470 and 1830°F. This burner has been tested on a 179 tons/day regenerative end-port gas-fired container furnace. NOx emissions reductions are reported to be around 65 to 70 percent. This burner has not been tested on flat glass furnaces. No information is available on the applicability of this burner on pressed/blown glass furnaces.
(Reference: Pages 5-64 to 5-69, ACT)

Oxy-firing/ Oxygen Enrichment

The use of an oxidant stream with high or elevated oxygen and low nitrogen content in lieu of combustion air has been shown to produce a savings in fuel consumption and reduced NOx emissions. Oxygen enrichment can be anywhere above its level in air (21 percent) up to about 99 percent. Oxygen enrichment above 90 percent is called oxy-firing. Oxy-firing has been used on container and pressed/blown glass melting furnaces. As per Praxair, about 200 commercial glass melting furnaces have been converted to or built as oxy-fuel firing over the past 15 years.[31]

Increasing oxygen concentration will cause the temperature of the flame to rise, which, absent a reduction in nitrogen content, would increase the formation of NOx. However, by preventing air infiltration and by the use of oxy-firing (thereby reducing nitrogen available for thermal NOx formation), NOx can be reduced by about 85 percent. Fuel savings have been reported to be as high as 15 percent with oxy-fuel firing.An additional benefit of oxy-firing is additional throughput of the glass melting furnace due to the higher flame intensity.

Figure 7-2 shows the evolution of the oxy-fuel fired furnace performance on energy and emissions, based on a few of the Praxair's container glass furnace conversion projects. As described by Praxair, the first project was the cross fired regenerative furnace at Gallo Glass and the air baseline data on natural gas consumption and emissions of NOx and particulates in 1990 are compared with those after the conversion to oxyfuel in 1991.

The baseline energy consumption of the 116 m^2 (1248 sq ft) furnace was about 935 Kcal/Kg (3.74 MMbtu HHV/ton) using 152 kwh/ton of electric boost for flint glass with 10% cullet. After

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[31] Kobayashi, H., "Advances in Oxy-Fuel Fired Glass Melting Technology", XX International Congress on Glass (ICG), Kyoto, Japan, September 26- October 1, 2004

the conversion to oxy-fuel firing, the energy consumption was reduced to 848 Kcal/Kg (3.39 MMbtu/ton) using 111 kwh/ton of electric boost at about the same pull. The approximate fuel consumption without electric boosting was calculated from a furnace energy balance analysis, which yielded about 1113 Kcal/Kg (4.45 MMbtu/ton) for the baseline air case and 963 Kcal/Kg (3.85 MMbtu/ton) for the oxy-fuel firing case. The baseline energy consumption of this furnace was relatively high because of the relatively low pull for the furnace size, the end of the campaign regenerator deterioration and the low cullet ratio. The furnace converted in 1996 showed energy consumption of less than 800 Kcal/Kg (3.2 MMBtu/ton) with 60% cullet in a 111 m^2 (1194 sq ft) furnace. The figure also shows the projected performance of 625 Kcal/Kg (2.5 MMBtu/ton) with 60% cullet for a furnace with a fully integrated batch and cullet preheater.[31]

Figure 7-2. Energy consumption and emissions from oxy-fuel fired container glass furnaces[31]

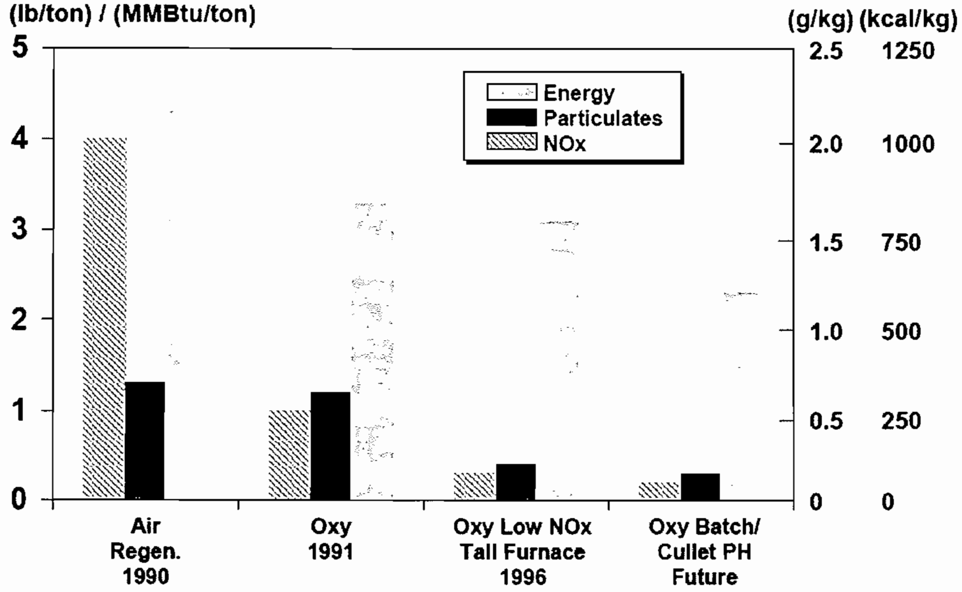
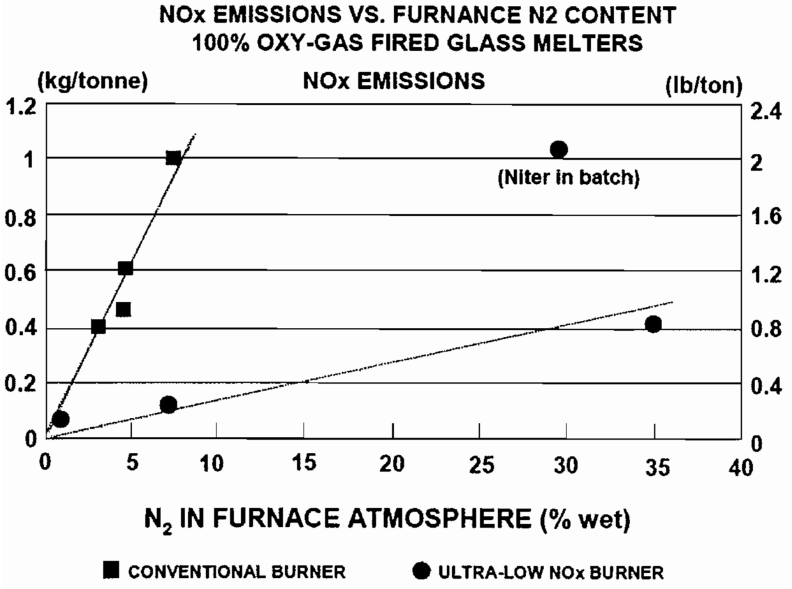


Figure 7-3 NOx Emissions from Glass Furnaces[31]

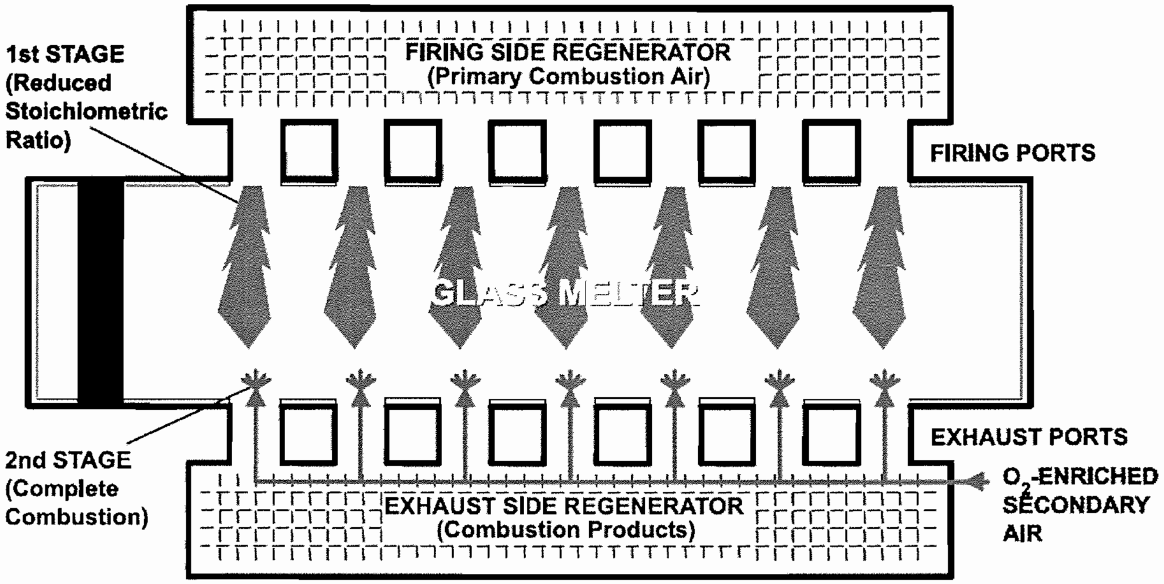


The conversion of an air fired furnace to oxy-fuel firing typically results in NOx reduction by 80 to 90% while the nitrogen concentration in the furnace is reduced from about 70% in an air-fired furnace to about 5 to 10% in a typical oxy-fuel fired furnaces. Results of NOx emissions tests conducted on several glass furnaces fired with natural gas-oxygen are plotted in Figure 7-3. As shown in Figure 7-3, NOx emissions are directly proportional to nitrogen concentration and are also affected by the burner design. Burners designed to achieve good combustion with low peak flame temperature will produce significantly lower NOx emissions than a conventional burner.

Oxygen-Enriched Air Staging (OEAS)

Another technology that can be used to reduce NOx that takes advantage of air staging and oxygen-enriched combustion is Oxygen-Enriched Air Staging (OEAS). In OEAS, a two-stage combustion process is used – a fuel-rich stage and an oxygen-rich stage – that is similar in principle to the air-staging methods used very successfully in other combustion systems to reduce NOx emissions. The amount of combustion air through the firing ports is reduced to decrease the oxygen available in the flame's high temperature zone in the first combustion stage. This reduces NOx formation but leads to higher carbon monoxide (CO) and unburned hydrocarbon levels. Oxygen-enriched air is injected into the furnace near the exit port(s) to complete combustion in the second stage within the furnace.

Figure 7-4. Oxygen Enriched Air Staging on a Sideport Glass Furnace
http://www1.eere.energy.gov/industry/glass/pdfs/airstaging.pdf



OEAS can operate on sideport furnaces which are used for nearly 65% of U.S. glass production. It can also be employed on endport furnaces.[32]

According to the Gas Technology Institute, OEAS has been successfully retrofit to seven endport container glass furnaces and three sideport container glass furnaces. NOx was reduced 50-70% on endport furnaces with no adverse impacts on other emissions, furnace performance, or glass quality. When OEAS technology was applied to a 300 ton/d six-port pair sideport furnace, NOx decreased by 40% to below 2.5 lb/ton. The system has been operating continuously for 6 years. OEAS systems subsequently installed on two 320 ton/d sideport furnaces reduced NOx by as

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[32] http://www.gastechnology.org/webroot/app/xn/xd.aspx?it=enweb&xd=4reportspubs%5C4_8focus%5Coxygenenrichedairstaging.xml

much as 70%. According to the US Department of Energy, the process is the most economical control technology for NOx emissions because fuel consumption is not increased. The technology also has no effect upon glass quality or furnace superstructure, and can even increase furnace productivity.[33]

Gas Reburn

Gas reburn is a form of fuel staging that reduces the NOx formed in the primary burn zone. Gas reburn may be applied to glass furnaces, and has been tested on them. Concerns relate to potential increases in fuel consumption as well as increases in furnace exit temperature. Gas reburn was tested at Anchor Glass Container`s Antioch plant [34]

Process Modifications

Process modifications include changes to the furnace, its combustion system, or its heat recovery system that can lower NOx emissions. In many cases, such modifications are designed to increase furnace productivity with lower NOx emissions as an added benefit.

Batch Preheat

It is possible to conserve energy as well as reduce NOx emissions significantly by preheating raw materials and cullet. In both cases, heat in the waste gases from the furnace exhaust can be used via direct heat transfer (contact with flue gas) or indirect heat transfer (plate heat exchanger). Alternatively low NOx conventional burners can be used for batch preheat. This preheating is done at a lower temperature and hence can result in net reduction of NOx emissions. The use of cullet itself can decrease energy consumption by 10- 12 percent over the use of virgin raw materials. Use of preheat can reduce energy consumption by 10 to 20 percent from reduced fuel usage and lower furnace temperatures resulting in corresponding NOx reductions.

Electric Boost

Some furnaces incorporate electric boost in order to boost the heat input to the melt with radiant heat transfer. Electric heaters can provide better temperature control and more intense heat input from radiation heat transfer. Electric boost will also reduce NOx emissions by reducing the necessary combustion temperature. The electric boost can be applied in a number of ways, including with electrodes inserted in the preheating end to control glass temperature and viscosity.

The use of cullet is generally restricted to container and pressed and blown glass production.

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[33] http://www1.eere.energy.gov/industry/glass/pdfs/airstaging.pdf

[34] http://www.osti.gov/energycitations/product.biblio.jsp?osti_id=616314

7.3.2 Post Combustion Controls

Post combustion controls are less commonly used on glass melting furnaces. However, controls that might be contemplated include

- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)

Selective Catalytic Reduction (SCR)

SCR could be employed on a glass furnace to achieve high levels of NOx removal (75% or more). Depending upon the exit temperature of the furnace after the checker brick, reheating might be needed. However, it is not anticipated that SCR would be used since less costly approaches would likely be employed to comply with the requirements of the proposed rule.

Selective Non-catalytic Reduction (SNCR)

SNCR is another technology that can be installed on glass melting furnaces, provided the correct temperature window is available for injection of the ammonia or urea reagent. This is difficult in light of the design of glass furnaces and the use of checker brick.

Table 7-3 summarizes the NOx emissions reductions potential of various control strategies for glass melting furnaces from the ACT document.

Table 7-3: NOx Emission Reductions for Various Control Technologies
(Table 2-2, page 2-7, ACT, Glass Melting Furnace, except for OEAS)

Technology	NOx Reduction (%)
Combustion Modifications	
Low NOx Burners (LNB)	40
Oxy-firing	85
OEAS	40-70
Process Modifications	
Modified Furnace	75
Cullet Preheat	25
Electric Boost	10
Post Combustion Modifications	
Selective Catalytic Reduction (SCR)	75
Selective non-Catalytic Reduction (SNCR)	40

7.3.3 Energy Saving Techniques

In addition to raw materials and cullet preheat described earlier, energy consumption can be reduced by refining of grain of raw materials, moisture control of raw materials used, improvement of fusibility of glass, work standards, prevention of air intrusion, heat insulation of furnace and other components, reduction of cooling air, waste heat recovery, development of thinner and lighter glass, and stabilization of production processes. Lowering of primary air pressure for fuel injection can also result in lower NOx emissions. Lowering of standard air volume can also reduce NOx emissions appreciably.

7.4 Cost Effectiveness of NOx Controls

In the Interim White Paper - Midwest RPO Candidate Control Measures, issued 12/02/2005, LADCO evaluated controls for glass furnaces and showed the cost effectiveness of controls as described by various sources. These results are shown in Table 7-4, and they are consistent with other estimates shown in Tables 7-5, 7-6, 7-7 and 7-8.

Table 7-4. Cost Effectiveness of NOx Controls on Glass Furnaces

Technology	**Description**	**Applicability**	**Performance**	**Cost[1] (S/ton)**
Low NOx Burners	Use of burner's designed to reduce peak flame temperature with slower mixing of fuel and air, minimum injection velocities, and higher emissivity flames	Not all furnace designs can accommodate longer flame length created by low-NOx burners	30 to 40% reduction in NOx 5.5 lbs NOx/ton for end-port furnaces 9 lbs NOx/ton for side-port furnaces	790 – 1,920 (EPA, 1994) 323 – 1,045 (IPCC, 2001)
Oxy-Firing	Replacing the combustion air with pure (>90%) oxygen thus reducing the nitrogen levels (thermal NOx) during combustion. Reduced air volumes result in higher energy efficiency.	Oil and gas fired furnaces. Currently used in greater than 25% of glass furnaces	75 to 85% reduction in NOx 1.25 to 4.1 lbs NOx/ton	2,150 - 4,400 (EPA, 1994) 1,254 – 2,542 (IPCC, 2001) 2,352 (DOE, 2002)
Oxygen-Enriched Air Staging (OEAS)	Staged combustion process where in first stage, reduces amount of primary combustion air entering firing port to reduce NOx formation followed by an oxygen-enriched second stage to complete combustion with no additional NOx formed	Successfully retrofit on endport and sideport regenerative furnaces	30 to 75% reduction in NOx	585 (DOE, 2002)
Batch Preheat	Raw materials and cullet preheated before adding to furnace. Heat from waste heat in furnace exhaust via direct heat transfer (contact with flue gas) or indirect heat transfer (plate heat exchanger). Alternatively, low-NOx conventional burner used for preheat. Preheat reduces heat-load for furnace thereby reducing NOx emissions.	When 50% or more cullet is used in feed for fossil fuel-fired furnaces	10 to 20% energy savings from reduced fuel usage and lower furnace temperatures resulting in corresponding reductions in NOx	890 -1,040 (EPA, 1994) 5,000 (DOE, 2002)
Electric Boost	Electric current passed through the glass mixture in furnace to provide heat, thus reducing fuel requirement and associated NOx generation.	Currently used in most container glass plants and in more than one half of all regenerative tank glass furnaces. Not viable for some colored glasses. Used to extend life of furnaces or increase capacity.	10 to 30% reduction in NOx 2.4 to 3.6 lbs NOx/ton	2,600 – 9,900 (EPA, 1994) 7,100 (DOE, 2002)
Fuel Switching – Gas to Oil	Oil combustion, while increasing fuel nitrogen, provides a flame higher in luminosity resulting in more efficient heat transfer than when gas is burned	Many furnaces can burn both fuels	30 to 50% reduction in NOx	

Fuel Reburn	Injection of fuel post combustion zone to creating reducing atmosphere for converting NO to N2; Includes" Reaction and Reduction in Regenerators" (3R) process which is based on injecting gas or oil into flue gas at regenerator entrance	Regenerative furnaces: successfully tested in wide range of glass plants	50 to 65% reduction in NOx	571 – 1,349 (for 3R, IPCC, 2001)
Selective Non Catalytic Reduction (SNCR)	Ammonia injection in furnace exhaust to creating reducing atmosphere for converting NOx to N2		20 to 60% reduction in NOx	830 – 2,000 (EPA, 1994) 840 – 1,617 (IPCC, 2001) 1,382 (DOE, 2002)
Selective Catalytic Reduction (SCR)	Same as SNCR but with use of catalyst at lower temperature		75 to 90% reduction in NOx	810 – 2,950 (EPA, 1994) 727 – 1,941 (IPCC, 2001) 3,000 (DOE, 2002)

[1] Cost data from EPA, Alternative Control Techniques Document (EPA, 1994); DOE, Technology Success Story: Glass, Oxygen-Enriched Air Staging (DOE, 2002); and IPCC, Best Available Techniques in the Glass Manufacturing Industry (IPCC 2001).

References:

- USEPA Alternative Control Techniques Document – NOx Emissions from Glass Manufacturing, EPA-453/R-94-037, June 1994.
- California Air Resources Board, Sources and Control of Oxides of Nitrogen Emissions, August 1997.
- New Jersey Department of Environmental Protection, State of Art Manual for the Glass Industry, July 1997.
- European Commission, Integrated Pollution Prevention and Control (IPPC) Bureau. Reference Document on Best Available Techniques in the Glass Manufacturing Industry. December 2001.
- U.S. DOE, Technology Success Story: Glass, Oxygen-Enriched Air Staging, Office of Industrial Technologies, www.oit.doe.gov/glass, April 2002.
- Glass Manufacturing Industry Council, Glass Melting Technology: A Technical and Economic Assessment, Prepared for the U.S. DOE Industrial Technologies Program, October 2004.

http://www.ladco.org/reports/rpo/Regional%20Air%20Quality/White%20Papers%20March%202006/Glass_Mfg_Ver2.pdf

Table 7-5. Cost Estimates from USEPA - 2006

8/21/06 -- Bill Neuffer, USEPA

http://www.epa.gov/groundlevelozone/SIPToolkit/documents/stationary_nox_list.pdf

Source category	**Identified by**	**Potential measure/control technology**	**Efficiency(%)**	**Cost effectiveness (S/T)**
Glass-container	LADCO, OTC, ACN	LNB	40	1,700
		SNCR	40	1,800
Glass – flat	ACN	Oxyfiring	40	700
		SCR	75	710(large)
		SNCR	40	700
Glass – Pressed	CAN	LNB	40	1,500
		SCR	75	2,500

Table 7-6: Cost Effectiveness- NOx Control Technologies For Glass Melting Furnaces (ACT)

Plant Size (tpd)	Cost Effectiveness ($/ton NOx Reduced) (January 1994 $)					
	LNB	Oxy-Firing	Cullet Preheat	Electric Boost	SCR	SNCR
50 (Pressed/Blown)	1680	4400	890	8900	2950[b]	1770[b]
250 (Container)	1920	5300	1040	8060	2460	2000
750 (Flat)	790	2150	NF[a]	2600	800	830[b] (990-1700)[c]

[a] Not Feasible

[b] Not demonstrated

[c] Two actual installations at 40 and 30% control, respectively

Table 7-7: NOx Control Cost Effectiveness for Glass Melting Furnaces (Reference: AirControlNet, Table B-7)

Type of Furnace	Control Measure	Typical Reductions	Annual Control Cost Effectiveness
Container	Cullet Preheat	25	940
Container	Electric Boost	10	7150
Container	LNB	40	1690
Container	SNCR	40	1770
Container	Oxy-Firing	85	4590
Container	SCR	75	2200
Flat Glass	Electric Boost	10	2320
Flat Glass	LNB	40	700
Flat Glass	Oxy-Firing	85	1900
Flat Glass	SNCR	40	740
Flat Glass	SCR	75	710
Pressed and Blown Glass	Oxy-Firing	85	3900
Pressed and Blown Glass	SNCR	40	1640
Pressed and Blown Glass	Electric Boost	10	8760
Pressed and Blown Glass	Cullet Preheat	25	810
Pressed and Blown Glass	SCR	75	2530

Table 7-8: NOx Control Cost Effectiveness Data for Glass Melting Furnaces
Reference: Table 7, Page 93, STAPPA/ALAPCO

NOx Control Technology	NOx Control Cost Effectiveness, $/Ton NOx Reduced		
	Flat Glass 750 tons/day*	Container Glass 250 tons/day*	Pressed and Blown Glass, 50 tons/day*
LNB	790	1920	1680
Oxy-Firing	2150	5300	4400
Cullet Preheat	--	1040	890
Electric Boost	2600	8060	9900
SCR	810	2460	2950
SNCR	830	2000	1770

8. Aluminum Melting Furnaces

8.1 Introduction

The purpose of this section is to provide a brief description of aluminum melting furnaces, the sources of NOx emissions, the baseline NOx emissions, the factors affecting baseline NOx emissions, the available NOx control technologies, and the estimated costs of controls.

The proposed rule affects aluminum melting furnaces located in the Chicago NAA and Metro-East NAA that have NOx emissions of 15 tons per year or more and 5 tons or more during the ozone season .

For those units affected by the rule, the emission limits of Table 8-1 are proposed.

Table 8-1. Proposed Emission Limit for Affected Aluminum Melting Furnaces

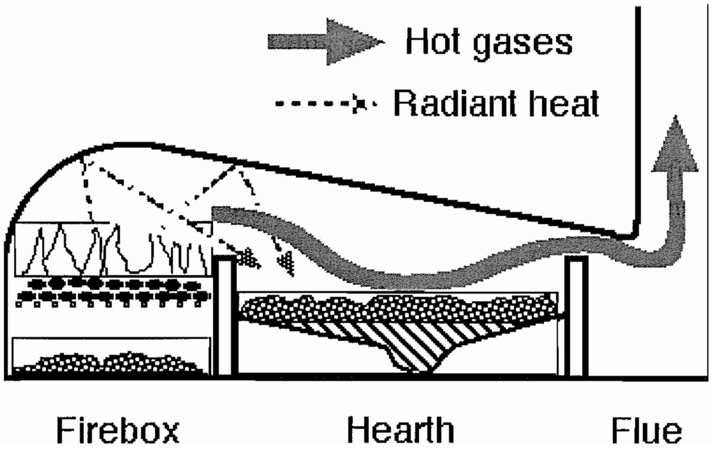
type	Limit lb/MMBtu
Reverberatory furnace	0.08
Crucible furnace	0.16

8.2 Process Description and Sources of Emissions

8.2.1 Process Description

Melting and refining of aluminum is primarily carried out in reverberatory furnaces at secondary aluminum production facilities. A reverberatory furnace is a metallurgical or process furnace that isolates the material being processed from contact with the fuel, but not from contact with combustion gases. The term *reverberation* is used here in a generic sense of rebounding or reflecting. In these furnaces, heating of charge is carried out by direct-fired wall-mounted burners. The primary mode of heat transfer is through radiation from refractory walls to the aluminum as in Figure 8-1, but convective heat transfer also provides additional heating from the burners. A typical reverberatory furnace has an enclosed melt area where the flame heat source reflects directly above the molten aluminum. After melting, aluminum flows into a melt area and then to a charging well and flows back into the melt section. Natural gas is the most common fuel used for melting aluminum. The melting of charge is carried at about 1200°F. Charge usually consists of clean aluminum scrap.

Figure 8-1. A Reverberatory Furnace.
www.britannica.com



Either cold air or preheated air may be used for combustion of a fuel in a burner. When the furnace uses preheated air, it may be preheated in a regenerative system or recuperative system. Some regenerative systems offer air preheats within 300°F of the furnace temperature. Recuperative systems offer lower air preheats.

Preheated air systems have not been widely used in aluminum melting furnaces because salt fluxing and impurities in the scrap mix can cause corrosion or fouling of downstream recuperators which may cause maintenance delays. Maintenance costs for regenerative burners and heat exchange media can offset the fuel savings, mitigating the advantage. Regenerative furnaces also have higher initial equipment costs and higher baseline NOx emissions compared to furnaces that use cold air.

After melting and refining, molten aluminum flows into one or more holding furnaces. Holding furnaces are suitable for final alloying and for making additional adjustments necessary to ensure that aluminum meets specifications. After alloying and degassing (if needed), molten aluminum is heated to casting temperature of about 1380°F. Pouring takes place from holding furnaces, either into molds or as feedstock for continuous casters.

Melting of aluminum can also be carried out in a crucible furnace, a metallurgical furnace consisting essentially of a pot of refractory material that can be sealed. The advantages of crucible furnaces are their ability to change alloys quickly, low oxidation losses, and their low maintenance costs. Disadvantages include lower efficiency, higher emissions per unit output, and size limitations. Energy efficiency of a crucible furnace can be improved by adding a ceramic matrix recuperator to the exhaust system to recover waste heat for preheating the combustion air.

There are two kinds of reverberatory furnaces: Side well reverberatory furnaces and direct charged furnaces. Side well reverberatory furnaces are equipped with a number of burners firing inside the hearth and against the furnace hot wall or door. A charging well and a pump well, when present, are connected to the furnace hot wall on the outside of the furnace. Both wells are connected to each other and with the furnace hearth by arches, which permit aluminum circulation between the furnace chambers. In direct charged furnaces, metal is charged directly into the furnace hearth where it is exposed to the open flames. These furnaces are compact and have high melting efficiencies and also widely used for melting aluminum.

Several types of burners are used in reverberatory melting furnaces. A brief description of these burners is given below.

Conventional Burners: These burners are very common in aluminum melting furnaces. They are either used to heat the refractory brick which radiates energy to the aluminum charge, or to transfer heat directly to the aluminum charge through flame impingement. Direct flame impingement increases the heat transfer efficiency, but also increases the metal oxidation loss. These burners are typically diffusion burners without air or fuel staging or regeneration.

Immersion Burners: These burners have been developed for aluminum melting. The burner housing is immersed in the molten aluminum and a pre-mixed burner provides hot combustion gases which are circulated through the housing. The combustion gases never come into contact with the molten aluminum, thus oxidation losses are minimized, and the submerged burner provides enhanced heat transfer to the molten charge, thus improving efficiency. Aluminum melting efficiencies are higher with immersion burners. Challenges in using a submersible burner is associated with its ability to withstand the conditions within the molten aluminum bath.

Oxygen Enriched Burners: These burners employ pure oxygen or oxygen enriched air which can significantly increase the combustion temperature of furnace burners. This results in significant fuel savings. As an example, 7 percent enrichment with pure oxygen can result in about 27 percent increase in aluminum melting rate, and about 24 percent reduction in gas consumption. Oxygen enhanced combustion can also result in lower NOx emissions through reduction of nitrogen content provided that flame temperature does not increase too much. The most common technique for the enrichment of air with oxygen involves mixing pure oxygen with the combustion air upstream of the burner. This is the most common method used since it requires no physical changes to the furnace, and is capable of being used on conventional burners with enrichment levels up to 25 percent. Alternatively, pure oxygen can be used in place of oxygen enriched air. These oxy-fuel burners are typically water cooled and combust a mixture of natural gas and pure oxygen. These burners operate at very high temperatures and produce almost no NOx emissions. These burners are typically not used in the aluminum melting industries.

Radiant Tube Burners: These burners are used in applications where reduced metal oxidation and low emissions are of importance. Radiant tubes burn natural gas inside an inner tube which then passes the combustion gases across an outer tube. The outer tube is made of high radiation emitting material, which transfers the heat via radiation to the intended application. The combustion and combustion gases are contained entirely inside the radiant tube and never come into contact with the aluminum charge. These burners often have air preheaters built into them to improve fuel efficiency.

Regenerative Burners: Regenerative combustion systems alternate combustion and air preheat through a pair of highly efficient heat storage beds. Combustion air passing through the hot bed is raised to about 1800°F providing 30-35 percent better efficiency than with conventional radiant roof-fired reverberatory furnaces. Regenerative ceramic burners produce high levels of air preheat (about 85% of process temperature), which with a combustion efficiency of up to 75 percent, bring fuel savings of up to 60-65%.

The application of regenerative burners is becoming increasingly common with the rising energy costs. Regenerative burners can reduce energy costs by 5 to 25 percent. Historical problems with regenerative systems are high NOx production and high maintenance costs.

Also, a regenerative system can increase the base cost of a furnace by 60 to 80 percent.

8.2.2 NOx Formation and Sources of NOx Emissions

This section covers how NOx is formed during the combustion of fuel in the air, factors that affect emissions of nitrogen oxides emissions, and provides a summary of uncontrolled or baseline NOx emissions from reverberatory and crucible furnaces.

8.2.3 Baseline or Uncontrolled NOx Emissions

Most aluminum furnaces use natural gas for heating and melting aluminum scrap. Natural gas contains very small amount of fuel nitrogen and hence most of NOx formed is thermal NOx. Thermal NOx is formed when nitrogen present in the air combines with oxygen in the air.

Baseline NOx emissions are influenced by furnace type, fuel characteristics, peak flame temperature, and oxygen concentration. Reverberatory furnaces used for aluminum melting either use cold air or preheated air. For preheated air, either regenerative or recuperative furnace is used, though former is most common. Some regenerative furnaces produce high levels of air preheat that result in high combustion efficiencies and possibly higher NOx. Table 8-2 on the following page shows emissions from uncontrolled aluminum melting furnaces.

Table 8-2. Emission Factors for Uncontrolled Aluminum Melting Furnace
"Energy and Environmental Profile of the U.S. Aluminum Industry" repared by Energetics -July 1997].
http://www1.eere.energy.gov/industry/aluminum/pdfs/aluminum.pdf

Source	**NOx, kg/metric ton, [lb/ton]**
Smelting furnace - crucible	0.85 [1.7]
Smelting furnace - reverberatory	0.4 [0.8]

As shown, uncontrolled NOx emissions are about 0.8 lb/ton of hot metal from reverberatory melting furnaces and 1.7 lb/ton of hot metal from crucible furnaces. Since about 5.5 mmBtu of energy is consumed to melt a ton of aluminum, uncontrolled NOx emissions are about 0.15 lb/mmBtu (126 ppm at 3% O_2) from a reverberatory furnace and 0.31 lb/mmBtu (260 ppm at 3% O_2) from a crucible furnace.

84 ppmv at 3% O_2 = 0.10 lb/mmBtu (Bloom Engineering paper on "Next Generation of Combustion Technology for Aluminum Melting"' by David Shalles)

8.3 Technical Feasibility of NOx Controls

There are two approaches to NOx controls:

- Combustion control approaches where the emphasis is on reducing NOx formation, and
- Post-combustion control approaches which destroy the NOx formed in the combustion process.

In addition, increase in luminosity of flame helps better heat transfer from the flame to the melt.

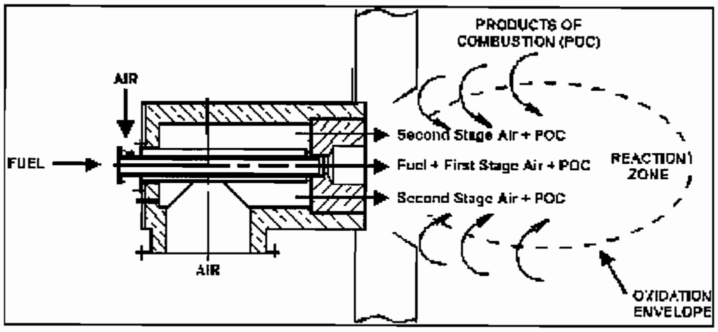
Combustion controls such as LNB and flue gas recirculation (FGR) fit into the first category. Sometimes, FGR is incorporated into the LNB design. Add-on flue gas treatment controls such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) are examples of the second. Wherever practicable, combustion control techniques should be used as they are generally cheaper compared to post combustion controls.

8.3.1 Combustion Controls

There are a number of types of combustion controls that have been used. Most use a form of air staging and/or flue gas recirculation. In addition, there are methods that use oxygen enrichment with air staging. The following are types of combustion controls:

1. Low NOx regenerative burners with air staging and self recirculation
2. Ultra Low NOx burners with exhaust gas recirculation
3. Ultra Low NOx burners with internal flue gas recirculation and baffles to create necessary air and fuel flow jet patterns, and use of high luminosity flame to transfer heat from flame to the melt.
4. Oxygen enhanced combustion
5. Oscillating combustion: It is expected to be used in aluminum melting furnaces.
6. NOx combustion system integrated with an innovative low-cost vacuum-swing-absorption (VSA) oxygen system

Figure 8-2. Staged air burner with external FGR
www.bloomeng.com/tmspaper-FINAL.doc



Some suppliers have developed burners that use air staging in combination with internal flue gas recirculation. The principal is shown in Figure 8-2. Fuel is admitted with primary air in the center of the burner to form a fuel-rich zone where NOx is not formed. Secondary air is admitted at the periphery, through individual ports to help burn out remaining fuel. Exhaust gas is entrained into the flame, which helps to reduce oxygen level and peak flame temperature within the flame, thereby reducing NOx formation in the burn-out zone.

Performance of this burner is shown in Figure 8-3 along with the performance of conventional burners, LNB, and LNB with external FGR. External FGR is more costly due to the need for additional fans and ductwork. So, this air staged burner with internal FGR is capable of achieving similar NOx to LNB with external FGR.

Figure 8-3. Performance of Bloom Engineering Lumiflame burner
http://www.bloomeng.com/1150lumiflame.pdf

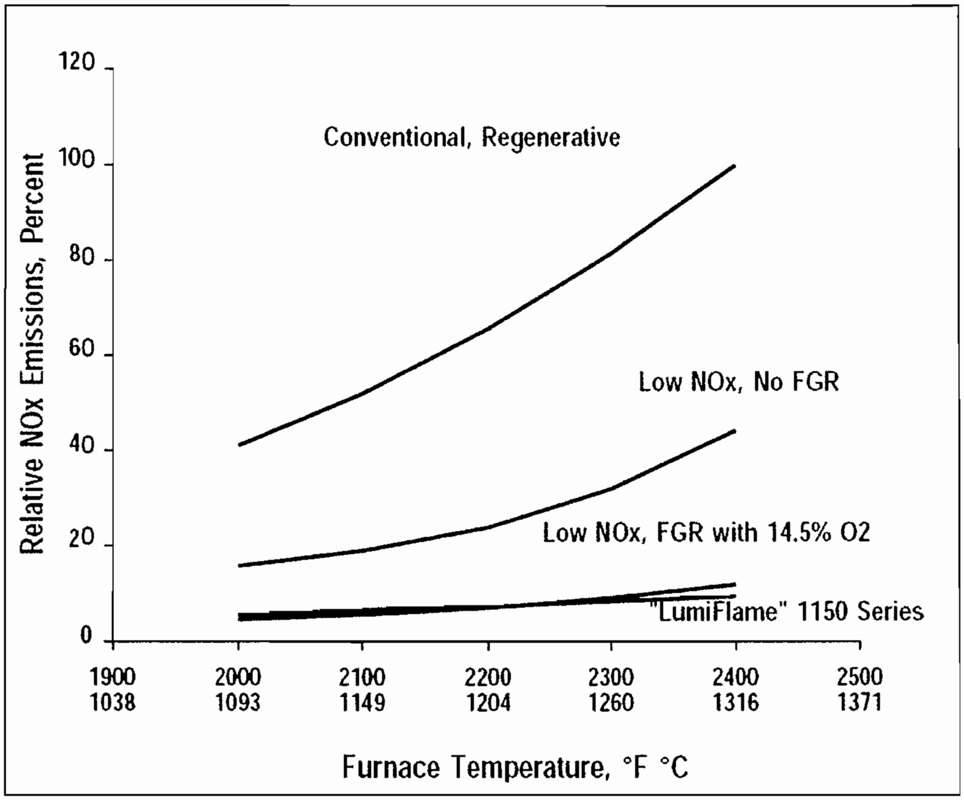


Figure 8-4. Oscillating Combustion
http://www.eere.energy.gov/industry/combustion/pdfs/oscllcomb.pdf

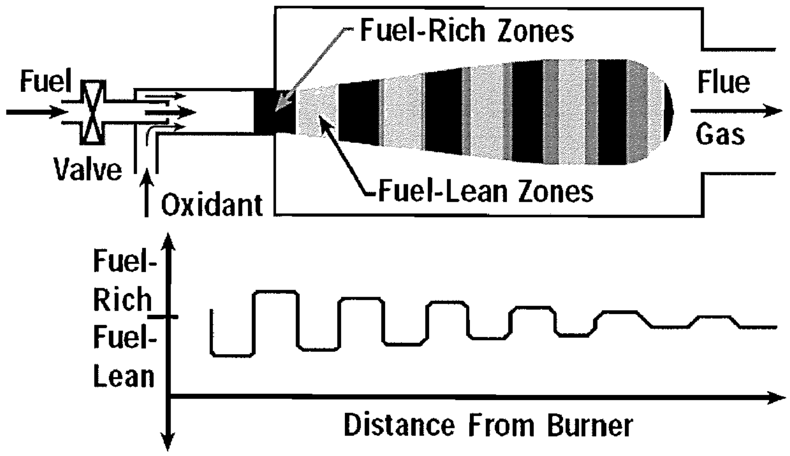


Figure 8-4 shows the principle of oscillating combustion, which uses alternating fuel-rich/fuel-lean zones to stage combustion and reduce NOx. This technology has been used in steel furnaces and could be employed in aluminum furnaces as well.

Table 8-3 shows the performance of NOx controls installed at a number of facilities. As shown these facilities all achieved NOx emissions below the levels required by this rule.

Table 8-3. Performance of low NOx combustion controls

Burner Type	**Uncontrolled NOx Emissions**	**NOx Control**	**NOx Emissions**
Regenerative Burner	As high as 1.0 lb/mmBtu	Air Staging and Self Circulation	<67 ppm @3% O_2 (0.08$^{(1)}$ lb/mmBtu)
Regenerative Burner	As high as 1.0 lb/mmBtu	ULNB w/ baffles to create jet flow of air and fuel, use of luminous flame, self circulation	< 50ppm$^{(2)}$ @3% O_2 (<0.06 lb/mmBtu)
Burner with no Preheat		Oxygen Enhanced Combustion. Uses a special air-oxy natural gas burner. Air enriched with 35-50% Oxygen.	0.323 lb/ton $^{(3)}$ aluminum (0.04 lb/mmBtu).
Conventional Burner		Oscillating Combustion. $^{(5)}$ Oscillation of fuel flow	NOx reduction 55-75%. $^{(4)}$

(1) The furnace was installed at Ford Motor Co. at its plant in Ypsilanti, MI. The reverberatory furnace capacity is 40,000 lb of aluminum. Melting efficiency is 1400 Btu/lb. Air is preheated to 1800°F. Natural gas consumption was reduced by 60% compared to the existing furnace.

(2) ULNB was designed by Bloom Engineering. The ULNB was installed on a 120-ton aluminum melting furnace at Alcan Rolled Product's Oswego, New York plant.

(3) The system has been installed on Wabash Alloys Furnace #8 in East Syracuse, NY.

(4) Tested and developed by IGT. Field demonstrations were made on an iron melter in a foundry, a batch annealing furnace in a steel plant, and on an oxy-fuel-fired melter in a glass plant. Not tested on any aluminum melter.

(5) Oscillating combustion creates successive NOx formation-retarding fuel-rich, fuel lean zones within the flame. Heat transfer from the flame to the load is increased due to more luminous fuel-rich zones and the break-up of thermal boundary layer. The increased heat transfer shortens heat-up time, thereby increasing thermal efficiency. Fuel efficiency is increased by about 13 percent and NOx emissions are reduced by about 55-70 percent. Oscillating combustion can also be used with oxy-fuel burners.
http://www.eere.energy.gov/industry/combustion/pdfs/oscllcomb.pdf

8.3.2 Post-Combustion Controls

Post-combustion controls include SCR and SNCR. These technologies are not generally applied to aluminum melting facilities. Combustion controls should be adequate to comply with this proposed rule.

8.4 Cost Effectiveness of NOx Controls

Figure 8-5 – Cost Effectiveness of Combustion Controls

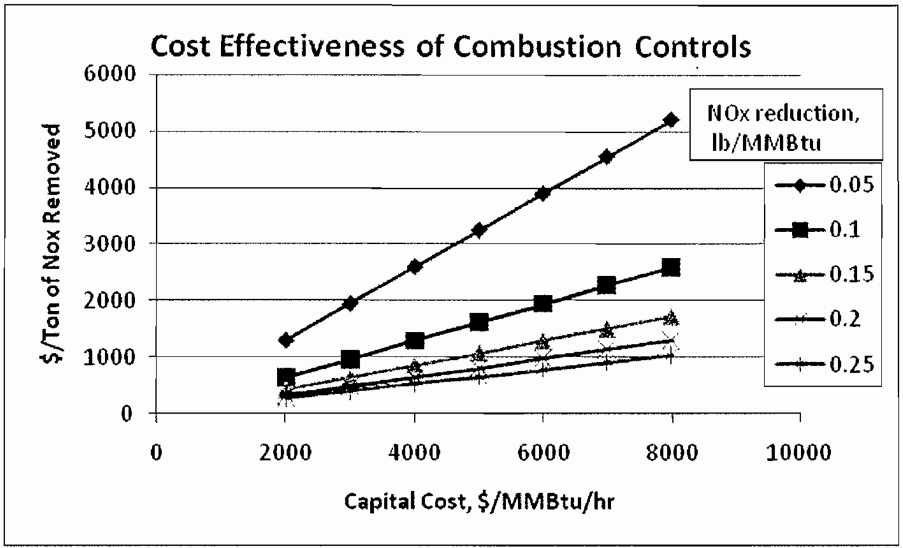


Figure 8-5 is identical to Figures 3-7 and 6-3, and it is a generic figure that shows cost effectiveness (in $/ton) for combustion controls. For a burner that does not use external FGR, this figure should be representative. If a facility operates less than 8000 hours per year, then the costs will be somewhat higher.

Nevertheless, as shown in Figure 8-5, for capital costs in the range of $5000/MMBtu/hr (typical, if not at the high end for a low NOx burner fully installed), costs are generally well below $1000/ton and, except in the case of very low NOx reductions (or, alternatively very low operating hours) are below $2500/ton. Even at very high installed costs, NOx reductions are generally below $2500/ton – except for very small NOx reductions.

In the case of combustion methods that incur additional operating costs, such as oxy-firing, Figure 8-5 would not apply. Costs similar to those shown for other sources (iron furnaces or glass melting furnaces) would likely apply.

8.5 Other State Regulations

As a benchmark, other state regulations have been examined, and these are shown below. As shown, the proposed rules are not more stringent than any of these other rules.

California, South Coast	0.300 lb NOx/ ton produced.	Year 2000
(Rule 2002)	0.323 lb/ton metal produced.	Year 2000
	0.055 lb/mmBtu.	Year 2010

Ref: http://www.aqmd.gov/rules/reg/reg20/r2002.pdf

BACT for New Aluminum Furnaces in SCAQMD
NOx limit: 37 ppmvd at3% O_2. (about 0.044 lb/MMBtu) Furnace size: 12.8 mmBtu/hr.
NOx limit: 39 ppmvd at3% O_2. Furnace size: 6 mmBtu/hr
NOx limit: 40 ppmvd at3% O_2 (BACT). Furnace size: 8 mmBtu/hr.
NOx limit: 60 ppmvd at 3% O_2. Furnace size: 31.5 mmBtu/hr.

Ohio EPA: Permit issued on 12/21/2004 to General Aluminum Mfg Co., Connecticut
Furnace Size: 7.0 mmBtu/hr, NOx limit: 1.05 lb/hour (Equal to 0.15 lb/mmBtu)
Furnace Size: 10.5 mmBtu/hr, NOx limit: 1.58 lb/hour (Equal to 0.15 lb/mmBtu)
Furnace Size: 5.8 mmBtu/hr, NOx limit: 0.87 lb/hour (Equal to 0.15 lb/mmBtu)

9. Continuous Emissions Monitoring Systems (CEMS)

The proposed rule will require the use of CEMS on all boilers and process heaters with heat inputs greater than 100 mmBtu/hr or other affected sources with a potential to emit one ton per day or more of NOx. Large boilers, with heat inputs greater than 250 mmBtu/hr will be required to install CEMS systems that comply with 40 CFR Part 75, while other boilers and process heaters with heat inputs greater than 100 mmBtu/hr or other affected sources with a potential to emit one ton per day or more of NOx will be required to install CEMS systems that comply with 40 CFR Part 60, Subpart A, and Appendix B, Performance Specifications 2 and 3, and Appendix F, Quality Assurance Procedures. Smaller units that are subject to performance testing requirements may, however, install and operate a CEMS in accordance with 40 CFR Part 60, Subpart A, and Appendix B, Performance Specifications 2 and 3, and Appendix F, Quality Assurance Procedures.

Some of the major differences between Part 60 CEMS and Part 75 CEMS are the following:

- The requirement to monitor flow with Part 75
- The requirement to monitor opacity with Part 75 (at least on coal and oil)
- More extensive Q/A and data handling requirements

CEMS are a proven technology. However, they do add cost to the operation of a facility affected by the rule. To estimate the impact of this cost, USEPA's CEMS cost estimating tool was used. The CEMS cost model may be downloaded at: http://www.epa.gov/ttn/emc/cem.html. It should be kept in mind that this model was developed primarily with power plants in mind, particularly Part 75 systems, and the costs are more reflective of a utility CEMS. In fact, the model does not allow for differences in stack height, or explicitly distinguish between Part 60 and Part 75 systems.

Three types of systems were modeled with this Microsoft Excel workbook:

- A 40 CFR Part 60 CEMS (NOx CEMS without flow, opacity or SO_2)
- A 40 CFR Part 75 CEMS without SO_2 monitoring (NOx CEMS with flow, opacity but not SO_2)
- A 40 CFR Part 75 CEMS with SO_2 monitoring (NOx CEMS with flow, opacity and SO_2)

In all cases it was assumed that the unit did not have an existing CEMS.

Tables 9-1, 9-2 and 9-3 show the results of the modeling. As shown on these tables, annual costs range from roughly $55,000 to $100,000. Because this model was developed primarily for power plants, which have much larger chimneys and are much more costly to install CEMS on, these costs may be high for industrial facilities that have much smaller chimneys and are generally much less expensive to install and operate CEMS at.

Table 9-1. Estimated costs for a NOx CEMS without Flow or Opacity using USEPA CEMS Cost model

First Costs	Labor	Test	ODCs	Total
Planning	2,390	0	0	2,390
Select Equipment	9,123	0	357	9,480
Support Facilities	0	0	28,865	28,865
Purchase CEMS Hardware	0	0	87,969	87,969
Install and Check CEMS	6,852	0	13,088	19,940
Performance Specification Tests	1,958	8,055	275	10,287
QA/QC Plan	2,335	14,039	50	16,424
	22,658	22,093	130,604	175,356
Annual Costs				
Day-to-Day Activities	8,027	0	2,000	10,027
Annual RATA	1,011	7,668	0	8,679
PM Monitor RCA	0	0	0	0
PM Monitor RRA	0	0	0	0
Cylinder Gas Audits (ACA/SVA for PM)	1,561	0	1,496	3,057
Recordkeeping and Reporting	3,710	0	160	3,870
Annual QA & O&M Review and Update	2,312	0	2,529	4,841
Capital Recovery	3,227	3,146	18,598	24,971
Total w/o capital recovery	16,621	7,668	6,185	30,475
Total with capital recovery	19,848	10,814	24,783	55,445

Table 9-2 Estimated cost for a CEMS with Flow and Opacity but without SO_2 using USEPA CEMS Cost model

First Costs	Labor	Test	ODCs	Total
Planning	3,331	0	0	3,331
Select Equipment	14,643	0	377	15,020
Support Facilities	0	0	33,765	33,765
Purchase CEMS Hardware	0	0	154,103	154,103
Install and Check CEMS	9,377	0	15,441	24,818
Performance Specification Tests	2,222	12,068	350	14,640
QA/QC Plan	3,100	18,149	50	21,300
	32,674	30,218	204,085	266,977
Annual Costs				
Day-to-Day Activities	17,891	0	2,750	20,641
Annual RATA	1,072	11,201	0	12,273
PM Monitor RCA	0	0	0	0
PM Monitor RRA	0	0	0	0
Cylinder Gas Audits (ACA/SVA for PM)	1,699	0	1,710	3,409
Recordkeeping and Reporting	14,702	0	200	14,902
Annual QA & O&M Review and Update	3,392	0	5,468	8,860
Capital Recovery	4,653	4,303	29,062	38,018
Total w/o capital recovery	38,756	11,201	10,128	60,085
Total with capital recovery	43,409	15,504	39,190	98,103

Table 9-3. Estimated costs for a NOx CEMS with Flow, Opacity and SO_2 using USEPA CEMS Cost model

First Costs	Labor	Test	ODCs	Total
Planning	3,475	0	0	3,475
Select Equipment	15,115	0	383	15,499
Support Facilities	0	0	37,265	37,265
Purchase CEMS Hardware	0	0	172,547	172,547
Install and Check CEMS	10,532	0	16,248	26,780
Performance Specification Tests	2,280	12,333	425	15,038
QA/QC Plan	3,271	19,178	50	22,499
	34,674	31,511	226,918	293,103
Annual Costs				
Day-to-Day Activities	19,138	0	3,250	22,388
Annual RATA	1,137	11,468	0	12,606
PM Monitor RCA	0	0	0	0
PM Monitor RRA	0	0	0	0
Cylinder Gas Audits (ACA/SVA for PM)	1,837	0	1,924	3,761
Recordkeeping and Reporting	15,931	0	200	16,131
Annual QA & O&M Review and Update	3,654	0	6,718	10,372
Capital Recovery	4,938	4,487	32,313	41,738
Total w/o capital recovery	41,698	11,468	12,092	65,258
Total with capital recovery	46,636	15,955	44,405	106,996

10. Potentially Affected Sources and Existing Regulations

Affected sources are those that emit or have the potential to emit 100 tons or more of NOx emissions per year. The NOx RACT emissions limitations apply to only those point sources that emit 15 tons of NOx per year and 5 tons of NOx during the ozone season. Point sources selected for NOx control include industrial boilers, process heaters, cement kilns, lime kilns, aluminum melting furnaces, reheat, annealing, and galvanizing furnaces located at iron and steel plants, glass melting furnaces, and EGU boilers.

10.1 Description of Affected Sources and Regulations

Industrial boilers larger than 250 mmBtu/hour and all EGU boilers larger than 25 megawatt capacity are currently subject to the NOx SIP Call regulations promulgated under 35 Ill. Adm. Code 217, Subparts U and W, respectively, in 2001. A computer search of the 2005 NOx emissions inventory showed that there are 10 industrial boilers and 13 electric utility boilers located in the Chicago NAA and two industrial boilers and five EGU boilers in the Metro-East NAA that are subject to the NOx SIP Call regulations. These boilers are also subject to the NOx General Requirements under proposed Subpart C of 35 Ill. Adm. Code Part 217.

The NOx SIP Call regulations promulgated under 35 Ill. Adm. Code Part 217, Subpart T, affect cement kilns, but currently there are no cement kilns in the Chicago NAA and the Metro-East NAA . A member of the cement industry has initiated discussions pertaining to the construction of a cement kiln in the Chicago NAA.

There is only one facility producing lime in the Chicago NAA and it has two rotary coal-fired lime kilns. There are no gas-fired lime kilns in the Chicago NAA and Metro-East NAA.

There are no aluminum melting furnaces currently in operation in non-attainment areas. Pechiney Rolled Products LLC, located in the Chicago NAA, was shut down recently in 2004. The company may decide to restart in future or a new aluminum melting furnace may be constructed in the non-attainment area. These furnaces are not currently subject to NOx control regulations.

Point sources considered for NOx control at iron and steel plants include reheat, annealing, and galvanizing furnaces. These sources are not currently subject to NOx control regulations.

There are two glass melting facilities in the Chicago NAA with a total of four glass melting furnaces producing container glass. There is no flat glass or pressed and blown glass production facility in either non-attainment area. Currently there are no NOx control regulations for glass melting facilities.

There are two iron and steel plants in the Chicago NAA and Metro-East NAA that have reheat, annealing, and galvanizing furnaces. The current galvanizing furnace at U.S. Steel Granite City Works does not produce 15 tons of NOx annually, and hence is not shown in our inventory.

The NOx inventory was generated through the use of year2005 annual emission reports submitted pursuant to 35 Ill. Adm. Code Part 234. For our purpose, year 2005, instead of year 2002, was selected because some sources have been either shut down or modified since 2002. This is particularly true concerning steel plants, aluminum melting furnaces, and EGU boilers. Many EGU boilers have installed NOx controls to meet the stringent Acid Rain regulations.

Boilers and process heaters are encompassed under the proposed rule. They are grouped together as fuel combustion emission sources. For our purpose, indirect heat transfer from a fuel combustion source to gaseous or liquid materials other than water is considered a process heater. Pipeline heaters and storage tank heaters are excluded from this definition.

Fluidized catalytic cracking units (FCCU) at petroleum refineries are large emitters of NOx emissions, but currently all FCCU units are subject to consent decrees. CO boilers, which are part of FCCU, are also subject to the consent decrees. To avoid any conflict with the compliance schedule, these sources are not being considered for NOx controls under this NOx RACT proposal. Therefore, the proposed rule does not apply to FCCU, their regenerator and associated CO boiler or boilers and CO furnace or furnaces where present, that commenced operation prior to January 1, 2008, if such units are located at a petroleum refinery and such units are required to meet emission limits for NO_x as provided for in an enforceable order.

Table D-1 lists all sources potentially subject to NOx RACT regulations in the Chicago NAA and Metro-East NAA, respectively. Table E-1 lists only those sources which are subject to existing SIP Call regulations.

10.2 Estimation of NOx Reductions

An estimation of NOx reductions from industrial boilers was made by using baseline NOx emission factors as provided for in the ACT document for Industrial/Commercial/Institutional boilers and proposed NOx RACT limits. As an example, average baseline NOx emissions from natural gas-fired industrial boilers greater than 100 mmBtu/hour is 0.26 lb/mmBtu and the proposed NOx RACT limit is 0.08 lb/mmBtu. Hence, an average of 69.2% of NOx emissions has to be reduced to achieve the proposed emission limit. All stoker boilers were assumed to be spreader stoker and all pulverized coal-fired boilers were assumed to be dry-bottom wall-fired for estimation of NOx reductions. There are no tangentially-fired industrial boilers in our inventory. Combustion tuning for boilers smaller than or equal to 100 mmBtu/hour is assumed to provide about 15% reduction.

For an estimation of NOx reductions from process heaters, all process heaters were assumed to be of the natural draft type, since information about draft type is not available. This assumption is reasonable since, nationwide, about 90% of process heaters are of the natural draft type. Baseline emissions were taken from the ACT document for process heaters. Uncontrolled NOx emissions vary significantly with the nitrogen content of the fuel. For our purpose, all gaseous fuels were assumed to be natural gas, and all liquid fuels were assumed to be distillate fuel. Combustion tuning for process heaters smaller than or equal to 100 mmBtu/hour is assumed to provide about 15% reduction.

For iron and steel reheat, annealing, and galvanizing furnaces, information about whether the furnace is regenerative, recuperative, or air heat type is not available in our inventory. For our estimations of emissions reductions, it was assumed that these furnaces are recuperative type, based on our discussion with U.S. Steel Granite City Works. For the purpose of calculating emissions reductions, baseline NOx emissions and average NOx reductions as provided in the ACT document for low NOx burner and flue gas recirculation control technology were taken.

For aluminum melting furnaces, there is no ACT document available, and hence, baseline NOx emissions were based on a computer search and 50% NOx reduction was assumed by the NOx RACT limits for estimation of NOx reductions. Since there are no operating aluminum melting furnaces in the non-attainment areas, the actual reduction will be zero.

For glass melting furnaces, baseline NOx emissions vary depending upon the type of glass produced and furnace used. For an estimation of NOx reductions, 50% NOx control was assumed. Only container glass melting furnaces are located in the non-attainment areas.

Since there are no cement kilns in the non-attainment areas, the actual reduction will be zero. For lime kilns, 30% NOx control was assumed for the estimation of NOx reduction.

EGU boilers subject to the proposed NOx RACT regulations burn coal as the primary fuel. Some of these boilers also burn natural gas or fuel oil as a startup fuel or as pilot fuel. Emissions resulting from natural gas and oil combustion are small as compared to coal-firing. Therefore, those emissions are ignored for our purpose. Year 2005 baseline emission data was taken from the USEPA's Clean Air Markets Division (CAMD) website. The NOx control limit was applied to the baseline emissions to obtain NOx reductions.

Table F-1 provides NOx reductions from the application of the proposed NOx RACT limits to sources in the Chicago NAA and Table G-1 provides NOx reductions from the application of the proposed NOx RACT limits to sources in the Metro-East NAA. The tables provide both annual as well as typical ozone season day NOx emissions.

Table H-1 provides NOx reductions from the application of proposed NOx RACT limits. As can be seen from Table H-1, overall about 46% of emissions will be reduced by the application of NOx RACT limits, and the majority of the emissions reduction will come from EGU boilers.

Table I-1 provides category wide NOx reductions from the application of proposed NOx RACT limits. As can be seen from Table I-1, overall about 46.3% of emissions will be reduced by the application of NOx RACT limits, and the majority of the emissions reduction will come from EGU boilers.

Table 10-1 summarizes NOx reduction in the Chicago NAA and Metro-East NAA by category.

Table 10-1. Summary of NOx reduction in Chicago and Metro-East Non-Attainment Areas by Source Category.

Source Category	Size	No. of Units	2005 Base Year NOx, tpy	Controlled NOx, tpy	NOx RACT Reductions, tpy	NOx Reduction, %
Industrial Boilers	>100 mmBtu/hr	45	4300.1	1219.1	3081.6	71.7
Industrial Boilers	<100 mmBtu/hr	35	998.2	848.4	149.7	15
Process Heaters	>100 mmBtu/hr	58	3733.7	2655.8	1077.9	28.9
Process Heaters	<100 mmBtu/hr	26	1004.95	854.21	150.74	15
Glass Melting Furnaces	>15 tpy NOx	4	732	366	366	50
Lime Kilns	>15 tpy NOx	2	734.4	514.1	220.3	30
Iron and Steel Plant Furnaces	>15 tpy NOx	6	1052.6	249.6	803	76.3
EGU Boilers	>25 MW	20	32068.6	17252.1	14816.5	46.2
Grand Total		196	44625	23959	20666	46.3

Appendices to

TECHNICAL SUPPORT DOCUMENT

for

CONTROL OF NITROGEN OXIDE EMISSIONS

from

Industrial Boilers and Electrical Generating Unit Boilers
Process Heaters
Cement Kilns
Lime Kilns
Reheat, Annealing, and Galvanizing Furnaces used at Iron and Steel Plants
Glass Melting Furnaces
Aluminum Melting Furnaces

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Table A-1: Summary of NOx Reduction Performance for ICI Boilers

Boiler Type and Fuel	NOx Control	Range in Performance	
		Reduction Efficiency %	Controlled NOx lb/mmBtu
N. Gas-fired Single Burner Watertube	WI	50-77	0.04-0.056
	ULNB+FGR	53-74	0.01-0.08
	LNB	46-71	0.03-0.11
	LNB+FGR	55-84	0.018-0.09
	SCR	80+	0.01-0.06
N. Gas-fired Multi-Burner Watertube	BOOS+WI+OT	N/A	0.05-0.08
	LNB	39-52	0.10-017
	SNCR	50-72	0.03-0.19
	SCR	N/A	0.024
Distillate Oil Single Burner Watertube	LNB	N/A	0.08-0.33
	FGR	20-68	0.04-0.15
	LNB+FGR	N/A	0.03-0.13
	SCR	N/A	0.011
Residual-oil Single Burner Watertube	LNB	30-60	0.09-0.23
	FGR	4-30	0.12-0.25
	SCR	80-90	0.025-0.15
Residual-oil Multi-Burner Watertube	LNB	30-60	0.09-0.23
	LNB+OFA	N/A	0.22
	SCR	58-90	0.025-0.15
Pulverized Coal Wall-Fired	LNB	49-67	0.11-0.50
	SNCR	30-83	0.15-0.40
	SCR	80-90	0.08-0.18
Pulverized Coal Tangentially-Fired*	LNB		
	LNB+SCA		
	SCR	80-90	0.06-0.23
Coal-fired Stokers	Gas Cofiring	20-25	0.18-0.20
	RAP		
	SNCR	40-74	0.11-0.28
Coal-fired FBC	FGR+OFA	N/A	0.12-0.16
	SNCR	76-80	Under 0.10
	SCR	80+	Under 0.10
Wood-fired Stoker **	SNCR-Urea	25-80	0.04-0.23
Wood-fired FBC**	SNCR-NH3	44-80	0.035-0.20

* No Tangential-fired boiler in our inventory

** Wood-fired boilers are located at non-major sources (with PTE <100 tons/year)

Reference: Alternative Control Techniques Document- NOx Emissions from Industrial/ Commercial/Institutional (ICI) Boilers, EPA-453/R-94-022

Table A-2. Cost of NOx Controls from Khan, 2003

As noted in report, these results are Preliminary, and not Final and are presented for comparison only

NOx Technology Retrofit Costs
COAL-, GAS- & OIL-FIRED INDUSTRIAL BOILERS

Fuel	Technology	NOx Reduction %	Capacity Factor %	$/Ton of Pollutant		
				1000 MMBtu/hr	250 MMBtu/hr	100 MMBtu/hr
Coal	LNB, sub-bituminous	51	14	1520	2304	3033
			50	426	645	849
			83	256	389	512
Coal	LNB/OFA, sub-bituminous	65	14	1727	2608	3428
			50	496	743	972
			83	306	454	593
Coal	LNB/OFA, bituminous	51	14	2197	3317	4358
			50	634	947	1239
			83	392	581	757
Coal	SCR	80	14	4481	5924	7262
			50	1359	1766	2141
			83	876	1123	1349
Coal	SNCR	40	14	2962	4015	4970
			50	1510	1814	2073
			83	1285	1473	1625
Gas	LNB/OFA	60	5	5260	7973	10521
			50	526	797	1052
			94	280	424	559
Gas	LNB/OFA/GR	80	5	6204	9415	12374
			50	656	981	1278
			94	368	543	700
Gas	SCR	80	5	14815	21095	26859
			50	1670	2330	2933
			94	986	1354	1689
Gas	SNCR	40	5	14,165	20,870	27,105
			50	2.452	3,116	3,735
			94	1,842	2,193	2.521
Oil	LNB/OFA (0.5 lb/MMBtu inlet NOx)	30	10	2630	3986	5260
			50	526	797	1052
			86	306	464	612
Oil	LNB/OFA/GR (0.5 lb/MMBtu Inlet NOx)	50	10	2505	3790	4973
			50	533	791	1028
			86	326	477	615
Oil	LNB/OFA/GR (0.36 lb/MMBtu Inlet NOx)	30	10	5694	8613	11303
			50	1210	1798	2337
			86	741	1085	1399
Oil	SCR (0.36 lb/MMBtu inlet NOx)	80	5	14,601	20,113	25,838
			50	1,622	2,178	2,767
			86	1,017	1.343	1,694
Oil	SCR (0.5 lb/MMBtu Inlet NOx)	80	5	10.458	14.443	18,544
			50	1,191	1,595	2,014
			86	760	997	1,245
Oil	SNCR (0.5 lb/MMBtu inlet NOx)	40	10	4271	5692	7399
			50	1749	2070	2367
			86	1485	1670	1840
Oil	SNCR (0.36 lb/MMBtu Inlet NOx)	40	10	5497	7753	9842
			50	1995	2444	2853
			86	1628	1889	2123

Khan, S. *Methodology, Assumptions, and References Preliminary NOX Controls Cost Estimates for Industrial Boilers.* http://cascade.epa.gov/RightSite/dk_public_collection_item_detail.htm?ObjectType=dk_docket_item&cid=OAR-2003-0053-0170&ShowList=xreferences&Action=view

Table A-3. Cost of NOx control for boilers, from NESCAUM 2000

Cost Effectiveness for NOx Reduction with LNB on a 350 MMBTU/hr Boiler 36% NOx reduction from 0.60 lb/MMBTU and Capital Cost of $5,000/MMBTU/hr		
Capacity Factor		
0.45	0.65	0.85
$1,378	$954	$730
Cost Effectiveness for NOx Reduction with LNB on a 350 MMBTU/hr Boiler 25% NOx reduction from 0.60 lb/MMBTU and Capital Cost of $5,000/MMBTU/hr		
Capacity Factor		
0.45	0.65	0.85
$1,985	$1,374	$1,051
Cost Effectiveness for burner modification on two 680 MMBTU/hr Boilers 10% NOx reduction from 0.43 lb/MMBTU and Capital Cost of $30,000, or $22/MMBTU/hr (Case Study BLR-2)		
Capacity Factor		
0.45	0.65	0.85
$30	$21	$16
Cost Effectiveness for NOx Reduction with LNB on one 350 MMBTU/hr Boilers 50% NOx reduction from 0.20 lb/MMBTU and Capital Cost of $5,000/MMBTU/hr		
Capacity Factor		
0.45	0.65	0.85
$2,977	$2,061	$1,576
Cost Effectiveness for LNB NOx Reduction on one 350 MMBTU/hr Boilers 25% NOx reduction from 0.20 lb/MMBTU and Capital Cost of $300/MMBTU/hr		
Capacity Factor		
0.45	0.65	0.85
$357	$247	$189
Cost Effectiveness for SNCR NOx Reduction on a 350 MMBTU/hr Boiler 35% NOx reduction from 0.45 lb/MMBTU		
Capacity Factor		
0.45	0.65	0.85
$1,814	$1,470	$1,300
Cost Effectiveness for SCR NOx Reduction on a 350 MMBTU/hr Coal-fired Boiler - 80% NOx reduction from 0.45 lb/MMBTU and Capital Cost of $10,000/MMBTU/hr		
Capacity Factor		
0.45	0.65	0.85
$2,179	$1,609	$1,307
Cost Effectiveness for SCR NOx Reduction on a 350 MMBTU/hr Coal-fired Boiler - 80% NOx reduction from 0.45 lb/MMBTU and Capital Cost of $15,000/MMBTU/hr		
Capacity Factor		
0.45	0.65	0.85
$3,006	$2,181	$1,745
Cost Effectiveness for SCR NOx Reduction on a 350 MMBTU/hr Boiler 80% NOx reduction from 0.15 lb/MMBTU and Capital Cost of $5,500/MMBTU/hr		
Capacity Factor		
0.45	0.65	0.85
$3,626	$2,603	$2,062
Cost Effectiveness for SCR NOx Reduction on a 100 MMBTU/hr Boiler 80% NOx reduction from 0.15 lb/MMBTU and Capital Cost of $7,500/MMBTU/hr		
Capacity Factor		
0.45	0.65	0.85
$6,110	$4,322	$3,376

Table A-4. Summary of cost of control for gas-fired refinery boilers (LADCO 2005)
Midwest Regional Planning Organization(RPO)Petroleum Refinery Best AvailableRetrofit Technology (BART)Engineering Analysis Prepared for:The Lake Michigan Air Directors Consortium

Gas Fired Boilers	LNB	
Uncontrolled emissions (tpy)	Removal Efficiency	40%
703	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$543,518	$6,938,915
Total Annual Costs	$221,120	$1,080,616
Pollutants Removed (tons/yr)	281	281
Cost per ton pollutant removed	$786	$3,841

Gas Fired Boilers	ULNB	
Uncontrolled emissions (tpy)	Efficiency	Efficiency
703	75%	85%
Total Capital Investment (TCI)	$2,144,309	$2,144,309
Total Annual Costs	$448,261	$448,261
Pollutants Removed (tons/yr)	528	598
Cost per ton pollutant removed	$850	$750

Gas Fired Boiler	LNB + FGR			
Uncontrolled emissions (tpy)	Removal Efficiency	50%	Removal Efficiency	72%
703	Low Capital Cost	High Capital Cost	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$877,238	$7,633,075	$877,238	$7,633,075
Total Annual Costs	$496,832	$1,404,769	$496,832	$1,404,769
Pollutants Removed (tons/yr)	352	352	506	506
Cost per ton pollutant removed	$1,413	$3,994	$981	$2,774

Gas Fired Boiler	SCR			
Uncontrolled emissions (tpy)	Efficiency	70%	Efficiency	90%
703	Low Capital Cost	High Capital Cost	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$2,015,650	$16,796,000	$2,015,650	$16,796,000
Total Annual Costs	$1,547,054	$3,533,429	$1,547,054	$3,533,429
Pollutants Removed (tons/yr)	492	492	633	633
Cost per ton pollutant removed	$3,142	$7,176	$2,444	$5,582

Gas Fired Boilers	LNB + SNCR			
Uncontrolled emissions (tpy)	Removal Efficiency	50%	Removal Efficiency	89%
703	Low Capital Cost	High Capital Cost	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$1,857,700	$11,772,867	$1,857,700	$11,772,867
Total Annual Costs	$976,279	$2,308,808	$976,279	$2,308,808
Pollutants Removed (tons/yr)	352	352	626	626
Cost per ton pollutant removed	$2,776	$6,565	$1,560	$3,688

Gas Fired Boiler	ULNB + SCR			
Uncontrolled emissions (tpy)	Removal Efficiency	85%	Removal Efficiency	97%
703	Low Capital Cost	High Capital Cost	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$4,159,959	$18,940,309	$4,159,959	$18,940,309
Total Annual Costs	$1,995,316	$3,981,690	$1,995,316	$3,981,690
Pollutants Removed (tons/yr)	598	598	682	682
Cost per ton pollutant removed	$3,337	$6,660	$2,925	$5,836

Process Heaters

Table B-1: Model Heaters: NOx Control Effectiveness, Capital Costs, and Cost Effectiveness for natural draft, Natural Gas-Fired Low and Medium Temperature Process Heaters (1991$)

Model Heater Capacity mmBtu/hr	Uncontrolled NOx Emissions, lb/mmBtu	NOx Control Technique	NOx Reduction	Controlled NOx, Lb/mmBtu	Capital Cost, $	Cost Effectiveness, $/Ton NOx Reduced @ Capacity Factor		
						0.10	0.50	0.90
17	0.098	(ND) LNB	50	0.049	58,200	25,400	5,070	2,820
	0.197	(MD) LNB	50	0.099	191,000	41,400	8,280	4,600
	0.098	(ND) ULNB	75	0.025	62,500	18,200	3,630	2,020
	0.197	(MD) ULNB	75	0.049	249,000	36,000	7,200	4,000
	0.098	(ND) SNCR	60	0.039	155,000	56,700	11,800	6,770
	0.197	(MD) SNCR	60	0.079	258,000	47,100	9,760	5,610
	0.197	(MD) SCR	75	0.049	951,000	14,100	28,700	16,200
	0.197	(MD) LNB+FGR	55	0.089	253,000	50,000	10,100	5,710
	0.098	(ND) LNB+SNCR	80	0.020	213,000	58,400	12,000	6,840
	0.197	(MD) LNB+SNCR	80	0.039	346,000	47,100	9,690	5,530
	0.197	(MD) LNB+SCR	88	0.024	995,000	132,000	26,700	15,100
36	0.098	(ND) LNB	50	0.049	92,600	19,100	3,810	2,120
	0.197	(MD) LNB	50	0.099	302,000	30,900	6,170	3,430
	0.098	(ND) ULNB	75	0.025	96,900	13,300	2,660	1,480
	0.197	(MD) ULNB	75	0.049	308,000	21,000	4,200	2,330
	0.098	(ND) SNCR	60	0.039	243,000	42,100	8,850	5,150
	0.197	(MD) SNCR	60	0.079	405,000	35,000	7,260	4,180
	0.197	(MD) SCR	75	0.049	1,500,000	106,000	21,700	12,300
	0.197	(MD) LNB+FGR	55	0.089	399,000	37,300	7,590	4,290
	0.098	(ND) LNB+SNCR	80	0.020	335,000	43,500	9,020	5,190
	0.197	(MD) LNB+SNCR	80	0.039	554,000	35,100	7,280	4,190
	0.197	(MD) LNB+SCR	88	0.024	1,570,000	99,200	20,200	11,400
77	0.098	(ND) LNB	50	0.049	133,000	12,800	2,570	1,430
	0.197	(MD) LNB	50	0.099	45,700	21,900	4,370	2,430
	0.098	(ND) ULNB	75	0.025	138,000	8,830	1,770	981
	0.197	(MD) ULNB	75	0.049	463,000	14,800	2,950	1,640
	0.098	(ND) SNCR	60	0.039	383,000	31,200	6,670	3,940
	0.197	(MD) SNCR	60	0.079	639,000	25,900	5,450	3,170
	0.197	(MD) SCR	75	0.049	2,390,000	80,100	16,400	9,370
	0.197	(MD) LNB+FGR	55	0.089	610,000	26,700	5,480	3,120
	0.098	(ND) LNB+SNCR	80	0.020	516,000	31,400	6,610	3,850
	0.197	(MD) LNB+SNCR	80	0.039	839,000	25,400	5,340	3,119
	0.197	(MD) LNB+SCR	88	0.024	2,480,000	74,100	15,200	8,640
121	0.098	(ND) LNB	50	0.049	232,000	14,200	2,840	1,580
	0.197	(MD) LNB	50	0.099	685,000	20,900	4,170	2,320
	0.098	(ND) ULNB	75	0.025	237,000	9,660	1,930	1,070
	0.197	(MD) ULNB	75	0.049	691,000	14,000	2,810	1,560
	0.098	(ND) SNCR	60	0.039	502,000	26,100	5,660	3,380

Model Heater Capacity mmBtu/hr	Uncontrolled NOx Emissions, lb/mmBtu	NOx Control Technique	NOx Reduction	Controlled NOx, Lb/mmBtu	Capital Cost, $	Cost Effectiveness, $/Ton NOx Reduced @ Capacity Factor		
						0.10	0.50	0.90
	0.197	(MD) SNCR	60	0.079	838,000	21,700	4,610	2,710
	0.197	(MD) SCR	75	0.049	3,160,000	67,900	14,000	8,020
	0.197	(MD) LNB+FGR	55	0.089	887,000	24,700	5,080	2,890
	0.098	(ND) LNB+SNCR	80	0.020	734,000	28,500	6,020	3,520
	0.197	(MD) LNB+SNCR	80	0.039	1,190,000	22,900	4,840	2,830
	0.197	(MD) LNB+SCR	88	0.024	3,370,000	64,300	13,200	7,550
186	0.098	(ND) LNB	50	0.049	346,000	13,800	2,760	1,530
	0.197	(MD) LNB	50	0.099	955,000	18,900	3,780	2,100
	0.098	(ND) ULNB	75	0.025	351,000	9,310	1,860	1,030
	0.197	(MD) ULNB	75	0.049	961,000	12,700	2,540	1,410
	0.098	(ND) SNCR	60	0.039	650,000	22,100	4,850	2,930
	0.197	(MD) SNCR	60	0.079	1,090,000	18,300	3,930	2,330
	0.197	(MD) SCR	75	0.049	4,130,000	58,200	12,100	6,940
	0.197	(MD) LNB+FGR	55	0.089	1,220,000	22,100	4,550	2,600
	0.098	(ND) LNB+SNCR	80	0.020	996,000	25,200	5,360	3,150
	0.197	(MD) LNB+SNCR	80	0.039	1,600,000	20,200	4,300	2,530
	0.197	(MD) LNB+SCR	88	0.024	4,460,000	55,700	11,500	6,600

Reference: Alternative Control Techniques Document- NOx Emissions from Process Heaters (Revised), EPA-453/R-93-034, Table 2-4

Table B-2: Model Heaters: NOx Control Effectiveness, Capital Costs, and Cost Effectiveness for mechanical draft, Natural Gas-Fired Low and Medium Temperature Process Heaters (1991$)

Model Heater Capacity mmBtu/hr	Uncontrolled NOx Emissions, lb/mmBtu	NOx Control Technique	NOx Reduction	Controlled NOx lb/mmBtu	Capital Cost, $	Cost Effectiveness, $/Ton NOx Reduced @ Capacity Factor		
						0.10	0.50	0.90
40	0.197	(MD) LNB	50	0.099	130,000	12,000	2,390	1,330
	0.197	(MD) ULNB	75	0.049	136,000	8,380	1,680	931
	0.197	(MD) SNCR	60	0.079	258,000	20,300	4,400	2,640
	0.197	(MD) SCR	75	0.049	1,270,000	91,500	1,870	10,600
	0.197	(MD) LNB+FGR	55	0.089	234,000	19,700	4,080	2,340
	0.197	(MD) LNB+SNCR	80	0.039	388,000	22,700	4,790	2,810
	0.197	(MD) LNB+SCR	88	0.024	1,400,000	85,200	17,400	9,880
77	0.197	(MD) LNB	50	0.099	282,000	13,500	2,700	1,500
	0.197	(MD) ULNB	75	0.049	288,000	9,200	1,840	1,020
	0.197	(MD) SNCR	60	0.079	383,000	15,700	3,480	2,130
	0.197	(MD) SCR	75	0.049	1,900,000	71,900	14,800	8,460
	0.197	(MD) LNB+FGR	55	0.089	436,000	19,100	3,960	2,270
	0.197	(MD) LNB+SNCR	80	0.039	665,000	20,200	4,300	2,530
	0.197	(MD) LNB+SCR	88	0.024	2,180,000	69,300	14,200	8,110
114	0.197	(MD) LNB	50	0.099	507,000	16,400	3,280	1,820
	0.197	(MD) ULNB	75	0.049	514,000	11,100	2,210	1,230
	0.197	(MD) SNCR	60	0.079	484,000	13,500	3,040	1,880
	0.197	(MD) SCR	75	0.049	2,420,000	62,800	12,900	7,410
	0.197	(MD) LNB+FGR	55	0.089	702,000	20,800	4,290	2,460
	0.197	(MD) LNB+SNCR	80	0.039	902,000	20,400	4,330	2,550
	0.197	(MD) LNB+SCR	88	0.024	2,930,000	62,800	12,900	7,390
174	0.197	(MD) LNB	50	0.099	541,000	11,500	2,290	1,270
	0.197	(MD) ULNB	75	0.049	548,000	7,730	1,550	859
	0.197	(MD) SNCR	60	0.079	624,000	11,400	2,630	1,660
	0.197	(MD) SCR	75	0.049	3,150,000	53,700	11,200	6,440
	0.197	(MD) LNB+FGR	55	0.089	792,000	15,400	3,220	1,860
	0.197	(MD) LNB+SNCR	80	0.039	1,170,000	15,700	3,410	2,040
	0.197	(MD) LNB+SCR	88	0.024	3,700,000	52,600	10,900	6,250
263	0.197	(MD) LNB	50	0.099	777,000	10,900	2,180	1,210
	0.197	(MD) ULNB	75	0.049	783,000	7,310	1,460	813
	0.197	(MD) SNCR	60	0.079	800,000	9,770	2,300	1,470
	0.197	(MD) SCR	75	0.049	4,090,000	46,500	9,730	5,640
	0.197	(MD) LNB+FGR	55	0.089	1,100,000	14,200	2,960	1,720
	0.197	(MD) LNB+SNCR	80	0.039	1,580,000	14,100	3,080	1,860
	0.197	(MD) LNB+SCR	88	0.024	4,860,000	46,100	9,580	5,530

Reference: Alternative Control Techniques Document- NOx Emissions from Process Heaters (Revised), EPA-453/R-93-034, Table 2-5

Table B-3: Model Heaters: Cost Effectiveness for Oil-Fired natural draft Heaters (1991$)

Model Heater Capacity mmBtu/hr	Uncontrolled NOx Emissions, lb/mmBtu	NOx Control Technique	NOx Reduction, %	Controlled NOx lb/mmBtu	Cost Effectiveness, $/Ton NOx Reduced @ Capacity Factor		
					0.10	0.50	0.90
69 Distillate Oil-Fired	0.20	(ND) LNB	40	0.120	15,100	3,030	1,680
	0.32	(MD) LNB	45	0.176	21,100	4,220	2,340
	0.20	(ND) ULNB	76	0.048	8,030	1,610	892
	0.32	(MD) ULNB	74	0.083	13,000	2,600	1,440
	0.20	(ND) SNCR	60	0.080	16,300	3,750	2,350
	0.32	(MD) SNCR	60	0.128	16,900	3,780	2,330
	0.32	(MD) SCR	75	0.080	51,800	11,000	6,490
	0.32	(MD) LNB+FGR	48	0.166	25,200	5,140	2,910
	0.20	(ND) LNB+SNCR	76	0.048	20,800	4,540	2,740
	0.32	(MD) LNB+SNCR	78	0.070	20,200	4,340	2,580
	0.32	(MD) LNB+SCR	86	0.045	51,500	10,900	6,360
69 Residual Oil-Fired	0.42	(ND) LNB	27	0.307	10,700	2,140	1,190
	0.54	(MD) LNB	37	0.340	15,300	3,060	1,700
	0.42	(ND) ULNB	77	0.097	3,770	753	419
	0.54	(MD) ULNB	73	0.146	7,790	1,560	866
	0.42	(ND) SNCR	60	0.168	7,880	1,900	1,230
	0.54	(MD) SNCR	60	0.216	10,100	2,280	1,420
	0.54	(MD) SCR	75	0.135	30,600	6,400	3,710
	0.54	(MD) LNB+FGR	34	0.356	20,700	4,220	2,390
	0.42	(ND) LNB+SNCR	71	0.122	10,700	2,420	1,490
	0.54	(MD) LNB+SNCR	75	0.135	12,500	2,740	1,650
	0.54	(MD) LNB+SCR	84	0.086	31,200	6,480	3,740

Reference: Alternative Control Techniques Document- NOx Emissions from Process Heaters (Revised), EPA-453/R-93-034, Table 6-10.

Table B-4: Model Heaters: Cost Effectiveness for Oil-Fired mechanical draft Heaters (1991$)

Model Heater Capacity mmBtu/hr	Uncontrolled NOx Emissions, lb/mmBtu	NOx Control Technique	NOx Reduction, %	Controlled NOx lb/mmBtu	Cost Effectiveness, $/Ton NOx Reduced @ Capacity Factor		
					0.10	0.50	0.90
135 Distillate Oil-Fired	0.32	(MD) LNB	45	0.176	5,920	1,180	658
	0.32	(MD) ULNB	74	0.083	3,680	735	408
	0.32	(MD) SNCR	60	0.128	8,010	2,000	1,340
	0.32	(MD) SCR	75	0.080	35,300	7,280	4,160
	0.32	(MD) LNB+FGR	48	0.166	9,570	2,010	1,170
	0.32	(MD) LNB+SNCR	78	0.070	9,580	2,230	1,410
	0.32	(MD) LNB+SCR	86	0.045	30,800	6,340	3,620
135 Residual Oil-Fired	0.54	(MD) LNB	37	0.340	4,290	858	477
	0.54	(MD) ULNB	73	0.146	2,210	442	245
	0.54	(MD) SNCR	60	0.216	4,830	1,280	880
	0.54	(MD) SCR	75	0.135	20,900	43,301,650	2,480
	0.54	(MD) LNB+FGR	34	0.356	7,870	1,450	961
	0.54	(MD) LNB+SNCR	75	0.135	6,000	3,820	942
	0.54	(MD) LNB+SCR	84	0.086	18,500	6,480	2,190

Reference: Alternative Control Techniques Document- NOx Emissions from Process Heaters (Revised), EPA-453/R-93-034, Table 6-11.

Table B-5: Model Heaters: Cost Effectiveness for ND Pyrolysis Heaters (1991$)

Model Heater Capacity mmBtu/hr	Uncontrolled NOx Emissions, lb/mmBtu	NOx Control Technique	NOx Reduction, %	Controlled NOx lb/mmBtu	Cost Effectiveness, $/Ton NOx Reduced @ Capacity Factor		
					0.10	0.50	0.90
84 Natural Gas	0.135	(ND) LNB	25	0.101	31,700	6,350	3,530
	0.135	(MD) LNB	25	0.101	82,200	16,400	9,130
	0.135	(ND) ULNB	50	0.068	16,100	3,230	1,790
	0.135	(MD) ULNB	50	0.068	41,500	8,300	4,610
	0.135	(ND) SNCR	60	0.054	22,000	4,780	2,870
	0.135	(MD) SNCR	60	0.054	36,400	7,660	4,470
	0.135	(MD) SCR	75	0.034	113,000	23,400	13,500
	0.135	(MD) LNB+FGR	55	0.061	47,000	9,600	5,440
	0.135	(ND) LNB+SNCR	70	0.041	30,200	6,360	3,720
	0.135	(MD) LNB+SNCR	70	0.041	48,200	9,970	5,720
	0.135	(MD) LNB+SCR	81	0.026	119,000	24,600	14,100
84 High Hydrogen Fuel Gas	0.162	(ND) LNB	25	0.121	26,400	5,250	2,940
	0.162	(MD) LNB	25	0.121	68,500	13,700	7,610
	0.162	(ND) ULNB	50	0.081	13,400	2,690	1,490
	0.162	(MD) ULNB	50	0.081	34,600	6,920	3,840
	0.162	(ND) SNCR	60	0.065	18,400	4,040	2,450
	0.162	(MD) SNCR	60	0.065	30,400	6,440	3,780
	0.162	(MD) SCR	75	0.040	94,300	19,600	11,300
	0.162	(MD) LNB+FGR	55	0.073	39,200	8,000	4,530
	0.162	(ND) LNB+SNCR	70	0.049	25,200	5,350	3,140
	0.162	(MD) LNB+SNCR	70	0.049	40,200	8,350	4,810
	0.162	(MD) LNB+SCR	81	0.031	99,500	20,600	11,800

Reference: Alternative Control Techniques Document- NOx Emissions from Process Heaters (Revised), EPA-453/R-93-034, Table 6-12.

Table B-6: NOx Control Cost Data for Process Heaters from AirControlNet (1990$)

Fuel	Source Size	NOx Control	Control Efficiency, %	Annual Cost Effectiveness, $/Ton NOx Controlled		
				Low	Typical	High
N. gas	Small Source	LNB	50		2200	
N. gas	Small Source	SCR	75		12,400	
N. gas	Small Source	ULNB	75		1500	
N. gas	Small Source	SNCR	60		2850	
N. gas	Small Source	LNB+FGR	55	3190	3190	15580
N. gas	Small Source	LNB+ SNCR	80	3520	3520	3520
Distillate oil	Small Source	ULNB	74		2140	
Distillate oil	Small Source	SNCR	60		3180	
Residual oil	Small Source	LNB+SCR	75	2230	2230	2860
Residual oil	Small Source	SNCR	60		1930	
Other Fuel	Small Source	SNCR	60		1930	
Other Fuel	Small Source	ULNB	73		1290	
Other Fuel	Small Source	LNB+SNCR	75	2230	2300	2860

Reference: AirControlNet Version 4.1, Documentation Report, September 2005. Appendix A

Table B-7: Control Cost Effectiveness Data for Process Heaters @ 90% Capacity Factor from STAPPA/ ALAPCO Report (Cost basis: 1993$)

Fuel	Control Technology	Unit Size mmBtu/hour	Control Efficiency, %	ND Heater	MD Heater
N. gas	LNB	25	50-60	2,050-2,560	1,650-2,070
	LNB	75	50-60	1,720-2,160	1,390-1,740
	LNB	200	50-60	1,100-1,370	890-1110
	Radiant Burner	25	90+	Requires Conversion to MD	2,340-2,610
	Radiant Burner	75	90+	Requires Conversion to MD	2,210-2,470
	Radiant Burner	200	90+	Requires Conversion to MD	2,170-2,420
	FGR	25	50-60	Requires Conversion to MD	1,300-1,500
	FGR	75	50-60	Requires Conversion to MD	8,70-1,050
	FGR	200	50-60	Requires Conversion to MD	630-750
	SNCR	25	20-50	8,190-10,920	4,620-6,170
	SNCR	75	20-50	5,870-7,820	3,370-4,500
	SNCR	200	20-50	4,500-6,000	2,640-3,510
	SCR	25	80-90	Requires Conversion to MD	3,300-3,800
	SCR	75	80-90	Requires Conversion to MD	2,600-3,500
	SCR	200	80-90	Requires Conversion to MD	2,000-2,700
Distillate Oil	LNB	25	30-60	1,430-1,790	1,340-1,680
	LNB	75	30-60	1,200-1,510	1,130-1,410
	LNB	200	30-60	770-960	720-900
	FGR	25	30-50	Requires Conversion to MD	1,580-2,100
	FGR	75	30-50	Requires Conversion to MD	1,070-1,420
	FGR	200	30-50	Requires Conversion to MD	770-1020
	SNCR	25	30-60	4,880-6,100	3,190-3,980
	SNCR	75	30-60	3,580-4,470	2,370-2,970
	SNCR	200	30-60	2,810-3,510	1,900-2,370
	SCR	25	80-90	Requires Conversion to MD	2,920-3,280
	SCR	75	80-90	Requires Conversion to MD	2,160-2,430
	SCR	200	80-90	Requires Conversion to MD	1,710-1,930
Residual Oil	LNB	25	30-60	680-850	800-1000
	LNB	75	30-60	580-720	670-840
	LNB	200	30-60	370-460	290-360
	FGR	25	30-50	Requires Conversion to MD	930-1250
	FGR	75	30-50	Requires Conversion to MD	630-840
	FGR	200	30-50	Requires Conversion to MD	450-600
	SNCR	25	30-60	2,410-3,010	1,950-2,440
	SNCR	75	30-60	1,790-2,230	1,470-1,840
	SNCR	200	30-60	1,420-1,780	1,190-1,490
	SCR	25	75-90	Requires Conversion to MD	1,630-1,830
	SCR	75	75-90	Requires Conversion to MD	1,180-1,330
	SCR	200	75-90	Requires Conversion to MD	910-1030

Data Source: Tables 4, 5 and 6 (Pages 49-50) of STAPPA/ ALAPCO Report: Controlling Nitrogen Oxides Under The Clean Air Act: A Menu of Options, July 1993.

Table B-8: Summary Table for Evaluation of Economic Reasonableness of NOx Control Limits for Various Process Heaters

Fuel	Furnace Type	Heater Size	Draft Type	Control Technology	Controlled NOx	Cost Effectiveness	TSD Reference	Original Reference
Natural Gas	Low & Med. Temperature	121-186	ND	LNB	0.049	1530-1580	Table 5	ACT
		121-186	ND/MD	LNB	0.099	2100-2320	Table 5	ACT
		121-186	ND	ULNB	0.025	1030-1070	Table 5	ACT
		121-186	ND/MD	ULNB	0.049	1410-1560	Table 5	ACT
		121-186	ND/MD	LNB+SNCR	0.039	2530-2830	Table 5	ACT
		Small	N/A	ULNB	0.025-0.049	1500	Table 10	AirControlNet
		200	ND	LNB	0.049	1100-1370	Table 11	STAPPA
		200	ND/MD	SCR	0.02-0.04	2000-2700	Table 11	STAPPA
		200	ND/MD	RB	0.02	2170-2420	Table 11	STAPPA
Natural Gas	Low & Med. Temperature	114-263	MD	LNB	0.099	1210-1820	Table 6	ACT
		114-263	MD	ULNB	0.049	813-1230	Table 6	ACT
		114-263	MD	LNB+SNCR	0.04	1860-2550	Table 6	ACT
		114-263	MD	LNB+FGR	0.09	1720-2270	Table 6	ACT
		200	MD	LNB	0.08-0.099	890-1110	Table 11	STAPPA
Distillate Oil	Low & Med. Temperature	69	ND	LNB	0.12	1680	Table 7	ACT
		69	ND/MD	LNB	0.176	2340	Table 7	ACT
		69	ND	ULNB	0.048	892	Table 7	ACT
		69	ND/MD	ULNB	0.083	1440	Table 7	ACT
		69	ND	SNCR	0.08	2350	Table 7	ACT
		69	ND/MD	SNCR	0.128	2330	Table 7	ACT
		Small	N/A	ULNB	0.08	2140	Table 10	AirControlNet
		200	ND/MD	SCR	0.032-0.064	1710-1930	Table 11	STAPPA
Distillate Oil	Low & Med. Temperature	135	MD	LNB	0.176	658	Table8	ACT
		135	MD	ULNB	0.083	408	Table 8	ACT
		135	MD	LNB+SNCR	0.07	1410	Table 8	ACT
		135	MD	SNCR	0.128	1340	Table 8	ACT
		135	MD	LNB+SCR	0.045	3620	Table 8	ACT
		200	MD	SCR	0.032-0.064	1710-1930	Table 11	STAPPA
Residual Oil	Low & Med. Temperature	69	ND	LNB	0.307	1190	Table 7	ACT
		69	ND/MD	LNB	0.340	1700	Table 7	ACT
		69	ND	ULNB	0.097	419	Table 7	ACT
		69	ND/MD	ULNB	0.146	866	Table 7	ACT
		69	ND	SNCR	0.168	1230	Table 7	ACT
		69	ND/MD	SNCR	0.216	1420	Table 7	ACT
		Small	ND/MD	LNB+SCR	0.135	2230-2860	Table 10	AirControlNet
		200	ND/MD	SCR	0.05-0.135	910-1030	Table 11	STAPPA
Residual Oil	Low & Med. Temperature	135	MD	LNB	0.340	477	Table8	ACT
		135	MD	ULNB	0.146	245	Table 8	ACT
		135	MD	LNB+SNCR	0.135	942	Table 8	ACT
		135	MD	SNCR	0.216	880	Table 8	ACT
		135	MD	LNB+SCR	0.086	2190	Table 8	ACT
		135	MD	SCR	0.135	2480	Table 8	ACT
		200	MD	SCR	0.05-0.135	910-1030	Table 11	STAPPA
Natural Gas	Pyrolysis Heater	84	ND	ULNB	0.068	1790	Table 9	ACT
		84	MD	ULNB	0.068	4610	Table 9	ACT
		84	ND	SNCR	0.054	2870	Table 9	ACT
		84	MD	SNCR	0.054	4470	Table 9	ACT
		84	MD	SCR	0.034	13500	Table 9	ACT
High Hydrogen Fuel Gas	Pyrolysis Heater	84	ND	ULNB	0.081	1490	Table 9	ACT
		84	MD	ULNB	0.081	3840	Table 9	ACT
		84	ND	SNCR	0.054	2450	Table 9	ACT
		84	MD	SNCR	0.054	3780	Table 9	ACT
		84	MD	SCR	0.040	11300	Table 9	ACT

* ACT cost year is 1991, STAPPA cost year is 2003 and AirControlNet cost year is 1990.

Table C-1: Fuel Tech SNCR Installation list (excluding EGU boilers and Waste to Energy)

INDUSTRY	PRODUCT TYPE	COUNTRY	COMPANY / LOCATION	# of units	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm, * lb/MMBtu)	RED'N %
Biomass	NOxOUT®	Italy	HRCI Rende, Italy	1	Grate-Fired	1 x 10500 Nm^3/h	Wood Waste	370 mg/Nm^3	46
Biomass	SNCR	Italy	C.C.T. Faenza, Italy	1	Confidential	Confidential	Confidential	Confidential	Confidential
Cement Kiln	NOxOUT®	Switzerland	Winterthur (1)	1	Sludge Incinerator	8.34	Sludge	200-300 mg/ Nm^3	60 - 73
Cement Kiln	NOxOUT®	Italy	Italcementi Calusco, Italy	1	Cement Kiln	270 t/h	Pet Coke	1500 mg/Nm^3	45
Cement Kiln	NOxOUT®	Italy	Italcementi Scafa, Italy	1	Cement Kiln	60 000 Nm^3/h	Pet Coke	1000 mg/Nm^3	35
Cement Kiln	NOxOUT®	France	Ciments Calcia Couvrot, France	1	Cement Kiln	323 495 Nm^3/h	Coke & Alternative Fuels	767 mg/Nm^3	65
Cement Kiln	SNCR	France	Maguin La Reunion, France	1	Rotary Kiln	8200 Nm^3/h	Animal Waste Products	300 mg/Nm^3	33
Cement Kiln	NOxOUT® [D]	USA	Ash Grove Cement Seattle, WA	1	Cement Kiln/ Pre-Calciner	160 tons solids/hr	Coal, Gas	350 - 600#/hr	> 80
Cement Kiln	NOxOUT® [D]	USA	Lehigh Portland Cement Mason City, IA	1	Cement Kiln/ Pre-Calciner	368	Coal, Gas	0.95-1.35 lb/MMBtu	25 - 35
Cement Kiln	NOxOUT®	USA	Cemex, Inc. Knoxville, TN	1	Pre-Calcining Kiln	317 MMBtu/hr	Coal & Pet Coke	570 ppmd	40
Cement Kiln	NOxOUT®	Taiwan	Taiwan Cement Units #3, #5, & #6	3	Cement Kiln/ Pre-Calciner	260 697 658	Coal Coal Coal	1.29 1.58 0.92	50 45 25
Cement Kiln	NOxOUT® [D]	Korea	Korean Cement Dong Yang Cement, Korea	1	New Suspension Calciner		Coal	1.27 lb/MMBtu	45

INDUSTRY	PRODUCT TYPE	COUNTRY	COMPANY / LOCATION	# of units	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm, * lb/MMBtu)	RED'N %
Cement Kiln	NOxOUT® [D]	Germany	Wulfrath Cement Germany	1	Cement Kiln	140	Lignite	1000 mg/Nm^3 500	90
Chemical	NOxOUT® [D]	USA	BP Chemicals Green Lake, TX	1	AOG Incin. HRSG	34	Waste Gas	330	80 +
Chemical	NOxOUT®	USA	BP Chemicals Green Lake, TX	3	AOG Incin. HRSG	398,757 lb/hr Flue Gas 398,757 lb/hr Flue Gas 238,361 lb/hr Flue Gas	Absorber OFF Gas	238 238 150	50 50 50
Chemical	NOxOUT®	USA	Miles, Inc. Kansas City, MO	1	Carbon Furnace Afterburner	16	Chemical Waste	150	35
Chemical	NOxOUT®	USA	N American Chem. Corp. Trona, CA	1	T-Fired	(2) 75 MWe	Coal	200	40
Chemical	NOxOUT®	Taiwan	Far East Textile	1	Front-Fired		Coal		50
Chemical	NOxOUT®	Taiwan	Formosa Plastics Kaohsiung	1	Front-Fired	331	Coal	500	60
Chemical	NOxOUT®	Taiwan	Formosa Plastics Kaohsiung	1	Front-Fired	331	Coal	500 mg/Nm^3 @ 11% O$_2$	60
Industrial	NOxOUT®	Germany	Hornitex	1	Incinerator	125	Wood	750 mg/Nm^3 370	43
Industrial	NOxOUT®	France	Ciments Calcia Bussac, France	1	Cement Kiln	208 060 Nm^3/h	Coke & Alternative Fuels	943 mg/Nm^3	69
Industrial	NOxOUT®	Belgium	CCB Gaurain four 3, Belgium	1	Cement Kiln	137 895 Nm^3/h	Coke & Alternative Fuels	1503 mg/Nm^3	50
Industrial	NOxOUT®	Belgium	CCB Gaurain four 4, Belgium	1	Cement Kiln	394 223 Nm^3/h	Coke & Alternative Fuels	1170 mg/Nm^3	60
IPP/Co-Gen	NOxOUT®	USA	U.S. Sugar Corp. Clewiston, FL	1	Grate-Fired	886	Bagasse	0.28 lb/MMBtu	50

INDUSTRY	PRODUCT TYPE	COUNTRY	COMPANY / LOCATION	# of units	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm, * lb/MMBtu)	RED'N %
IPP/Co-Gen	NOxOUT® [D]	USA	General Electric Lynn, MA	1	B&W "D" Type Pkg. Boiler	236	#6 Oil, Gas	0.28-0.31 lb/MMBtu	40 - 60
IPP/Co-Gen	NOxOUT® [D]	USA	Honey Lake Power Susanville, CA	1	Stoker-Fired	480	Wood	0.21 lb/MMBtu	52
IPP/Co-Gen	NOxOUT® [D]	USA	Oxford Energy Modesto #2, Wesley, CA	1	Moving Grate Incinerator	90	Tires	0.13 lb/MMBtu	40
IPP/Co-Gen	NOxOUT® [D]	USA	Ultrasystems Fresno, CA	1	CFB	280	Wood	150	70
IPP/Co-Gen	NOxOUT® [D]	USA	Yankee Energy Dinuba, CA	1	CFB	190	Wood Waste	0.10-0.18 lb/MMBtu	40 - 75
IPP/Co-Gen	NOxOUT®	USA	ABB Okeelanta Okeelanta, FL	1	Grate-Fired Stoker	660	Bagasse Wood, Coal	0.40-0.20 lb/MMBtu	40 - 60
IPP/Co-Gen	NOxOUT®	USA	ABB Osceola Osceola, FL	1	Grate-Fired Stoker	660	Bagasse Wood, Coal	0.40-0.20 lb/MMBtu	40 - 60
IPP/Co-Gen	NOxOUT®	USA	Alternative Energy, Inc. Ashland, ME	1	Zurn Stoker	500	Wood	0.30 lb/MMBtu	50
IPP/Co-Gen	NOxOUT®	USA	Alternative Energy, Inc. Cadillac, MI	1	Zurn Stoker	500	Wood	0.30 lb/MMBtu	50
IPP/Co-Gen	NOxOUT®	USA	Alternative Energy, Inc. Northeast Empire Livermore Falls, ME	1	Zurn Stoker	500	Wood	0.30 lb/MMBtu	50
IPP/Co-Gen	NOxOUT®	USA	Black & Veatch Genessee, MI	1	ABB CE Stoker	473	Wood	0.47 lb/MMBtu	60
IPP/Co-Gen	NOxOUT®	USA	Black & Veatch Grayling, MI	1	Zurn Stoker	440	Biomass	0.26 lb/MMBtu	60
IPP/Co-Gen	NOxOUT®	USA	Celanese Narrows, VA	1	Front Wall-Fired	315	Coal	.360 lb/MMBtu	35 - 40

INDUSTRY	PRODUCT TYPE	COUNTRY	COMPANY / LOCATION	# of units	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm, * lb/MMBtu)	RED'N %
IPP/Co-Gen	NOxOUT®	USA	Chewton Glen Energy Ford Heights, IL	1	Grate-Fired	240	Shredded Tires	0.195 lb/MMBtu	60
IPP/Co-Gen	NOxOUT®	USA	Cogentrix Richmond, VA	8	CE Stoker	(8) 28 MWe	Coal	350	40
IPP/Co-Gen	NOxOUT®	USA	Fibrominn, LLC Benson, MN	1	Grate-Fired	802 MMBtu/hr	Poultry & Natural Gas	0.32 lb/MMBtu	50
IPP/Co-Gen	NOxOUT®	USA	Georgia Pacific Brookneal, VA	1	Wellons 4-Cell	236	Mixed Wood	0.33 lb/MMBtu	38
IPP/Co-Gen	NOxOUT®	USA	Georgia Pacific Mt. Hope, WV	1	Cell-fired	240	Bark/Dust	0.25 lb/MMBtu	20
IPP/Co-Gen	NOxOUT®	USA	I.P. Masonite Towanda, PA	1	B & W	250	Sludge/Wood Waste, Coal	0.4 lb/MMBtu	50
IPP/Co-Gen	NOxOUT®	USA	Kenetech Energy Fitchburg, MA	1	Riley Stoker	225	Wood	0.26 lb/MMBtu	47
IPP/Co-Gen	NOxOUT®	USA	LFC Hillman, MI	1	Grate-Fired	190	Wood	0.22 lb/MMBtu	30
IPP/Co-Gen	NOxOUT®	USA	McMillan Bloedel Clarion, PA	1	EPI Fluid Bed Combustor	500	Wood Waste/ Hog Fuel	100	42
IPP/Co-Gen	NOxOUT®	USA	Michigan State Univ., Unit #4 East Lansing, MI	1	CFB	460	Coal	247	57
IPP/Co-Gen	NOxOUT®	USA	Michigan State Univ., Units #1-3 East Lansing, MI	3	Wall Fired Boiler	320 320 420	Coal	0.38-0.40 lb/MMBtu	34-38
IPP/Co-Gen	NOxOUT®	USA	Oxford Energy Sterling, CT	1	Grate-Fired	(2) 170	Tires	0.15 lb/MMBtu	50
IPP/Co-Gen	NOxOUT®	USA	Ridge Generating Polk County, FL	1	Zurn Stoker	550	Wood	0.35 lb/MMBtu	57

INDUSTRY	PRODUCT TYPE	COUNTRY	COMPANY / LOCATION	# of units	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm, * lb/MMBtu)	RED'N %
IPP/Co-Gen	NOxOUT®	USA	Riley Ultrasystems II Weldon, NC	1	Riley Front-Fired Boiler	505	Pulv. Coal	0.33 lb/MMBtu	50
IPP/Co-Gen	NOxOUT®	USA	Ryegate Power Station Ryegate, VT	1	Riley Stoker	300	Wood	0.20 lb/MMBtu	30
IPP/Co-Gen	NOxOUT®	USA	Sierra Pacific Bohemia Plant Lincoln, CA	1	Cell-Fired	(2) 130	Biomass	0.42 lb/MMBtu	50
IPP/Co-Gen	NOxOUT®	USA	Solvay Chemicals Units 1 & 2 Green River, WY	2	Stoker	155 MMBtu/hr	Coal	0.45 lb/MMBtu	35
IPP/Co-Gen	NOxOUT®	USA	Sonoco Huntsville, SC	1	FW/ Pyropower CFB	145	Coal	195	67
IPP/Co-Gen	NOxOUT®	USA	Trigen Cinergy St. Paul, MN	1	Front Wall Grate-Fired	555	Wood Waste	0.34 lb/MMBtu	56
IPP/Co-Gen	NOxOUT®	USA	Zachry Energy Hurt, VA	1	Riley Stoker	(3) 390	Wood	0.20 lb/MMBtu	46
IPP/Co-Gen	NOxOUT®	Taiwan	Far East Textiles Hsihpu	1	Stoker Boiler	190	Coal	550 @ 6% O_2	50
IPP/Co-Gen	NOxOUT® [D]	Sweden	Tekniskaverken Linkoping P3 Sweden	1	Stoker		Wood	800mg/Nm^3 @ 11% O_2	50
IPP/Co-Gen	NOxOUT®	Sweden	Nykoping, Units 1-3 Gotaverken Energy	3	CFB	135	Coal	120-130mg/Nm^3 @ 1% O_2	70
IPP/Co-Gen	NOxOUT®	Sweden	Tekniskaverken Linkoping P1 Sweden	3	Grate-Fired	3 x 12	Coal	400 mg/Nm^3 @ 4% O_2	50
IPP/Co-Gen	NOxOUT®	Puerto Rico	AES Guyama, Puerto Rico	2	CFB	250 MWe	Coal	0.13 lb/MMBtu	23
IPP/Co-Gen	NOxOUT®	Korea	Hyundai Korea Kumho Petrochemical	1	CFB	926	Pulv. Coal	275	56

INDUSTRY	PRODUCT TYPE	COUNTRY	COMPANY / LOCATION	# of units	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm, * lb/MMBtu)	RED'N %
IPP/Co-Gen	NOxOUT®	Korea	Korea ICC Units 1 - 3 Kumi Heat & Power Station Korea	3	Front Wall-Fired	530 530 530	Pulv. Coal Pulv. Coal Pulv. Coal	710 700 710	53 53 40
IPP/Co-Gen	NOxOUT®	Germany	FT GmbH Germany	5	Fire Tube Pkg. Boilers	10 - 20 MWe	Heavy Oil	700-800mg/ Nm^3	40 - 50
IPP/Co-Gen	NOxOUT®	Germany	Standardkessel Germany	31	Fire Tube Pkg. Boilers	10 - 20 MWe	Heavy Oil	700-800 mg/Nm^3	40 - 50
IPP/Co-Gen	NOxOUT®	Czech Republic	Strakonice	2	High Front Wall-Fired & Low Grate Fired	36-40	Lignite Brown Coal	600 mg/Nm^3	50
IPP/Co-Gen	NOxOUT®	Czech Republic	Deza Vitkovice	1	Wall Fired Boiler	362	Oil/Mazut	700 mg/Nm^3 @ 11% O_2	36
IPP/Co-Gen	NOxOUT®	Czech Republic	Trmice	2	Wall-Fired	490	Lignite	341 ppvd	57
IPP/Co-Gen	NOxOUT®	Czech Republic	Vitkovice	1	Front Wall-Fired	250	Hard Coal	600 mg/Nm^3 @ 11% O_2	50
Process Unit	NOxOUT® [D]	USA	Rollins Environmental Deer Park, TX	1	Haz Waste Incinerator	185	Chlorinated Chemical Waste, Soil	60 - 250	35 - 50
Process Unit	NOxOUT®	USA	Alcan Berea, KY	2	Decoater/ Afterburner	30,000 lbs of aluminum cans/hr	Gas	90 - 130	50 - 80 +
Process Unit	NOxOUT®	USA	Allis Minerals Oak Creek, WI	1	Rotary Kiln Incinerator	60	Paper Sludge	0.48 lb/MMBtu	57
Process Unit	NOxOUT®	USA	Chambers Medical Waste Incinerator Chambers County, TX	2	Simonds Incinerator	21	Medical and Municipal	0.48 lb/MMBtu	67.8
Process Unit	NOxOUT®	USA	Dow Chemical Midland, MI	1	Rotary Kiln w/ Afterburner	145	Haz Waste	720 - 740	40 - 55
Process Unit	NOxOUT®	USA	Eli Lilly Lafayette, IN	1	Haz Waste Incinerator	59	Haz Waste	290	70

INDUSTRY	PRODUCT TYPE	COUNTRY	COMPANY / LOCATION	# of units	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm, * lb/MMBtu)	RED'N %
Pulp & Paper	NOxOUT® [D]	USA	Boise Cascade Intl. Falls, MN	1	Hydrograte Stoker	395	Bark, Gas	0.14-0.19 lb/MMBtu	25 - 35
Pulp & Paper	NOxOUT®	USA	Babcock and Wilcox Bowater, Calhoun, TN	1	BFB	821	Wood/Sludge	0.35 lb/MMBtu	62
Pulp & Paper	NOxOUT®	USA	Garden State Paper, Unit #3 Garfield, NJ	1	Front-Fired Ind. Boiler	110	Fiber Waste	0.30 lb/MMBtu	50
Pulp & Paper	NOxOUT®	USA	Garden State Paper, Unit #4 Garfield, NJ	1	Front-Fired Ind. Boiler	172	Fiber Waste	0.20 lb/MMBtu	30
Pulp & Paper	NOxOUT®	USA	Jefferson Smurfit Jacksonville, FL	1	CE Grate-Fired	540	Coal, Bark, Oil	0.55-0.70 lb/MMBtu	20 - 35
Pulp & Paper	NOxOUT®	USA	McBurney Corp. Koda Energy, LLC Shakopee, MN	1	Biomass Cogen	23 MW	Biomass	0.45 lb/MMBtu 0.55 lb/MMBtu	55 64
Pulp & Paper	NOxOUT®	USA	Minergy Fox Valley Aggregate Plant Neenah, WI	1	B & W Cyclone	350	Paper Sludge/ Natural Gas	0.80 lb/MMBtu	62
Pulp & Paper	NOxOUT®	USA	P. H. Glatfelter Neenah, WI	1	Sludge Combustor	60	Paper Sludge	570	50
Pulp & Paper	NOxOUT®	USA	Potlatch Bemidji, MN	1	Wellons 4-Cell Burner	232	Wood Waste	0.30 lb/MMBtu	50
Pulp & Paper	NOxOUT®	USA	S. D. Warren Skowhegan, ME	1	CE Grate-Fired	900	Oil, Bark, Biomass	0.30 lb/MMBtu	46
Pulp & Paper	NOxOUT®	USA	Schenecady International Schenecady, NY	1					
Pulp & Paper	NOxOUT®	USA	Temple-Inland Orange, TX	1	B&W Grate-Fired Boiler	548	Bark Natural Gas	0.25 lb/MMBtu	40
Pulp & Paper	NOxOUT®	USA	Westvaco Phase I (Lukemill) #24 Luke, MD	1	B & W Cyclone	550	Coal	1.15 lb/MMBtu	50

INDUSTRY	PRODUCT TYPE	COUNTRY	COMPANY / LOCATION	# of units	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm, * lb/MMBtu)	RED'N %
Pulp & Paper	NOxOUT® [D]	Sweden	Sodra Skogsagarna Sweden	1	Recovery Boiler	900	Black Liquor	60 mg/Nm^3 @ 3% O$_2$	60
Pulp & Paper	NOxOUT®	Italy	Energy Products of Idaho Italy	1	BFB	70.2	Paper/Landfill Sludge	0.587 lb/MMBtu	60.5
Pulp & Paper	Ammonia SNCR	Italy	C.C.T. Verzuolo, Italy	1	Fluidized Bed	28.8 t/h	Paper Sludge		
Refinery	NOxOUT® [D]	USA	UNOCAL Los Angeles, CA	1	Calciner HRSG		Petroleum Coke	45	53
Refinery	NOxOUT® [D]	USA	UNOCAL Los Angeles, CA	1	CO Boiler	400	Refined Gas	140	68
Refinery	NOxOUT®	USA	ARCO CQC Kiln Los Angeles, CA	1	Calciner HRSG	651	Petroleum Coke	86	30
Refinery	NOxOUT®	USA	BP Toledo, OH	1	CO Boiler	518	Refinery Gas	95	22-35
Refinery	NOxOUT®	USA	MAPCO Petroleum Memphis, TN	1	Bottom-Fired Process Htr	177	Refinery Gas, Natural Gas	75	60
Refinery	NOxOUT®	USA	MAPCO Petroleum Memphis, TN	1	Bottom-Fired Process Htr.	50	Refinery Gas, Natural Gas	65	50 - 75
Refinery	NOxOUT®	USA	Mobil Oil Paulsboro, NJ	1	GT - HRSG	630	Refinery Gas	75	50
Refinery	NOxOUT®	USA	Mobil Oil Torrance, CA	1	CO Boiler	614	Refinery Gas	90	65
Refinery	NOxOUT®	USA	Pennzoil Shreveport, LA	1	CO Boiler/ Thermal Oxidizer		CO, Refinery Gas		
Refinery	NOxOUT®	USA	Pennzoil Shreveport, LA	1	CO Boiler/ Thermal Oxidizer	243	Natural Gas & Regen. Gas	0.27 lb/MMBtu	74

INDUSTRY	PRODUCT TYPE	COUNTRY	COMPANY / LOCATION	# of units	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm, * lb/MMBtu)	RED'N %
Refinery	NOxOUT®	USA	Powerine Santa Fe Springs, CA	1	CO Boiler	31 - 62	Refinery Fuel Gas	105	60
Refinery	NOxOUT®	USA	Powerine Santa Fe Springs, CA	1	Package Boiler	31 - 62	Refinery Fuel Gas	105	40
Refinery	NOxOUT®	USA	Shell Oil Martinez, CA	1	CO Boiler	(3) 222	Refinery Gas	230	65
Refinery	NOxOUT®	USA	Total Petroleum Alma, MI	1	CO Boiler	197	CO, Refinery Gas	1.20 lb/MMBtu	67
Refinery	NOxOUT®	Saudi Arabia	Mobil Oil/Macchi Yanbu, Saudi Arabia	1	Package Boiler	(3) 265	Vacuum Tower Bottoms Propane	0.40 lb/MMBtu	25
Steel	NOxOUT® [D]	USA	AK Steel Furnace No. 1 Rockport, IN	1	Annealing Furnace	110 MMBtu/hr	Natural Gas	0.12 lb/MMBtu	35 - 45
Steel	NOxOUT® Plus Urea SCR	USA	Nucor Steel, Crawfordsville, IN	1	Reheat/ Radiant	58.8 14.3	Natural Gas	0.227 lb/MMBtu 0.581 lb/MMBtu	76
Steel	NOxOUT® Plus Urea SCR	USA	Nucor Steel, Hickman, AR	1	Preheat/ Radiant	46.7 14.6	Natural Gas	0.32 lb/MMBtu 0.46 lb/MMBtu	76 79
Steel	NOxOUT® Plus Urea SCR	USA	Nucor Steel, Hugor, S.C.	1	Preheat/ Radiant	50.8 20	Natural Gas	0.44 lb/MMBtu 0.31 lb/MMBtu	82 89
Steel	NOxOUT® Plus Urea SCR	USA	SMS Demag/Nucor Steel, Decatur, AL	1	Annealing Furnace	98.7	Natural Gas	0.296 lb/MMBtu	77.3
Steel	NOxOUT®	USA	Selas/BHP Rancho Cucamonga, CA	1	Cont. Galv. Line	29	Natural Gas	105	65
Steel	NOxOUT®	USA	WAPC Iron Dynamics Butler, IN	1	Rotary Hearth	435	Natural Gas	0.374 lb/MMBtu	30
Steel	NOxOUT®	Taiwan	China Steel Unit 6	1	CE T-Fired w/CCOFA	535	Coal	410 mg/Nm^3 @ 11% O_2	43

INDUSTRY	PRODUCT TYPE	COUNTRY	COMPANY / LOCATION	# of units	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm, * lb/MMBtu)	RED'N %
Steel	NOxOUT®	Taiwan	China Steel Units 7 & 8 Taiwan - Republic of China	2	C.E. VU 40	156.8	Coal	0.568 lb/MMBtu	42.9
Steel	NOxOUT®	Italy	Demag Italimpianti S.p.A. Trieste, Italy	1	Coke Oven Incinerator	6200	Coke Oven OFF Gas	1200 mg/Nm^3 @ 11% O_2	70

Table C-2: NOx Reductions from the Application of NOx RACT (Reductions by Categories)

Emission Category Description	**Category Designation**	**No. of Entries**	**No. of Units**	**Heat Input mmbtu/hr**	**2005 NOx Emissions tpy**	**Estimated NOx RACT Reduction , %**	**Estimated Controlled NOx tpy**	**Estimated Nox Reduction Tons**	**Unit Typical Ozone Season NOx tons/day**	**Estimated Ozone Season Controlled NOx, TPD**	**Estimated Ozone season NOx Reduction, TPD**
Chicago NAA											
Gaseous Fuel-fired Boilers >100 mmBtu/hr, Total	1a1	22	34	6911.9	1196.5	69.2%	368.2	828.3	2.79	0.86	1.93
Gaseous fuel-fired Boilers < =100 mmBtu/hr, Total	1a2	6	20	1273.9	156.6	15.0%	133.1	23.5	0.63	0.54	0.09
Dist. oil Boilers >100 mmBtu/hr, Total	1b1	1	1	249	22.3	52.4%	10.6	11.7	0.040	0.02	0.02
Solid Fuel Boilers >250 mmbtu/hr, Total	1e2	3	3	997.5	2330.2	73.9%	607.9	1722.3	8.93	2.33	6.60
Solid Fuel <=250, >100 mmbtu/hr, Total	1e3	1	1	212	21.6	63.8%	7.8	13.8	0.00	0.00	0.00
Solid Fuel Boilers <=100 mmbtu/hr, Total	1e4	5	5	376.2	476.7	15.0%	405.2	71.5	1.61	1.37	0.24
Process Htrs Gas fired >100 mmBtu/hr, Total	2a1	16	41	6672.6	1526.0	28.6%	1090.0	436.0	4.19	2.99	1.20
Process Htrs Gas-fired< =100 mmBtu/hr, Total	2a2	9	10	720.3	213.3	15.0%	181.3	32.0	0.60	0.51	0.09
Process Htrs, Residual Oil-fired, >100 mmBtu/hr, Total	2b1	1	1	171	23.3	76.2%	5.5	17.7	0.07	0.02	0.05
Process Htrs, Other Oil-fired, <100 mmBtu/hr, Total	2c3	1	1	17	26.5	15.0%	22.5	4.0	0.10	0.09	0.02
Glass melting Furnaces, Total	3	1	4	45	731.9	50.0%	366.0	366.0	2.02	1.01	1.01
Lime Kilns, Total	5a	2	2	588.9	734.4	30.0%	514.1	220.3	2.54	1.78	0.76
Annealing Furnace, Iron and Steel, Total	7b	1	1	123	44.1	60.0%	17.6	26.5	0.15	0.06	0.09
EGU Coal-fired Boilers, Total	8a	13	15	37802	24827.2	57.3%	10612.9	14214.3	82.22	34.59	47.63
All Sources in Chicago NAA, Total		82	139	56160.30	32331	56%	14343	17988	105.9	46.2	59.7
Metro-East NAA											
Gaseous Fuel-fired Boilers >100 mmBtu/hr, Total	1a1	10	6	3460	730.1	69.2%	224.6	505.4	2.02	0.62	1.40
Gaseous Fuel-fired Boilers <=100 mmBtu/hr, Total	1a2	7	10	1305	364.9	15.0%	310.2	54.7	1.06	0.90	0.16
Process Htrs Gas fired >100 mmBtu/hr, Total	2a1	16	16	2776.7	2184.4	28.6%	1560.3	624.1	6.58	4.70	1.88
Process Htrs Gas fired <100 mmBtu/hr, Total	2a2	15	15	1395.3	765.2	15.0%	650.4	114.8	2.10	1.78	0.31
Reheat Furnaces, Iron and Steel, Total	7a	8	5	2681.6	1008.5	77.0%	231.9	776.5	4.62	1.06	3.56
EGU Coal-fired Boilers, Total	8a	5	5	22540	7241	8.3%	6639	602	20.6	18.8	1.8
All Sources in Metro-East NAA, Total		61	57	34158.60	12294	21.8%	9617	2678	37.0	27.9	9.1

Emission Category Description	Category Designation	No. of Entries	No. of Units	Heat Input mmbtu/hr	2005 NOx Emissions tpy	Estimated NOx RACT Reduction , %	Estimated Controlled NOx tpy	Estimated Nox Reduction Tons	Unit Typical Ozone Season NOx tons/day	Estimated Ozone Season Controlled NOx, TPD	Estimated Ozone season NOx Reduction, TPD
Chicago and Metro-East NAA (Combined)											
Gaseous Fuel-fired Boilers >100 mmBtu/hr, Total	1a1	32	40	10371.9	1926.5	69%	592.8	1333.8	4.8	1.5	3.3
Gaseous fuel-fired Boilers < =100 mmBtu/hr, Total	1a2	13	30	2578.9	521.5	15%	443.3	78.2	1.7	1.4	0.3
Dist. oil Boilers >100 mmBtu/hr, Total	1b1	1	1	249	22.3	52.4%	10.6	11.7	0.040	0.02	0.02
Solid Fuel Boilers >250 mmbtu/hr, Total	1e2	3	3	997.5	2330.2	73.9%	607.9	1722.3	8.93	2.33	6.60
Solid Fuel <=250, >100 mmbtu/hr, Total	1e3	1	1	212	21.6	63.8%	7.8	13.8	0.00	0.00	0.00
Solid Fuel Boilers <=100 mmbtu/hr, Total	1e4	5	5	376.2	476.7	15.0%	405.2	71.5	1.61	1.37	0.24
Process Htrs Gas fired >100 mmBtu/hr, Total	2a1	32	57	9449.3	3710.4	0.6	2650.3	1060.1	10.8	7.7	3.1
Process Htrs Gas-fired< =100 mmBtu/hr, Total	2a2	24	25	2115.6	978.5	0.3	831.7	146.8	2.7	2.3	0.4
Process Htrs, Residual Oil-fired, >100 mmBtu/hr, Total	2b1	1	1	171	23.3	76.2%	5.5	17.7	0.07	0.02	0.05
Process Htrs, Other Oil-fired, <100 mmBtu/hr, Total	2c3	1	1	17	26.5	15.0%	22.5	4.0	0.10	0.09	0.02
Glass melting Furnaces, Total	3	1	4	45	731.9	50.0%	366.0	366.0	2.02	1.01	1.01
Lime Kilns, Total	5a	2	2	588.9	734.4	30.0%	514.1	220.3	2.54	1.78	0.76
Reheat Furnaces, Iron and Steel, Total	7a	8	5	2681.6	1008.5	77.0%	231.9	776.5	4.62	1.06	3.56
Annealing Furnace, Iron and Steel, Total	7b	1	1	123	44.1	60.0%	17.6	26.5	0.15	0.06	0.09
EGU Coal-fired Boilers, Total	8a	18	20	60342.00	32068.6	46.2%	17252.1	14816.5	102.9	53.4	49.4
All Sources in Chicago and Metro-East NAA, Total		143	196	90318.9	44625	46.31%	23959	20666	142.9	74.1	68.9

Table D-1: Year 2005 NOx Inventory of Major Sources in NAAs

Mydocument/TSD/NOx RACT-Attachments.xls

Sr No	Facility ID	Source PTE TPY NOx	Facility Name	SIC	Emission Unit ID	Emission Point Description	Mode ID	Mode Description	SCC #	Emission Unit category	Heat Input Capacity mmbtu/hr	2005 NOx Emissions tpy	Unit Typical Ozone Season NOx tons/day	Fuel	descr1	descr3	descr4
1	031003ADA	516.7	Alsip Paper Condominium Assn	4931	0004	BOILERS #1 AND #2	01		10200601	1a1	310	173.1	0.2184	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
2	031012AAO	139.6	Nalco Co	2899	0049	BOILER #1	01	NATURAL GAS CO	10200601	1a1	114.6	17.9	0.0656	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
3	031012AAO	139.6	Nalco Co	2899	0061	BOILER #2	01	NATURAL GAS CO	10200601	1a1	124	42.3	0.2675	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
4	031012ABI	4542.4	Corn Products International Inc	2046	0046	UTILITIES - BOILER #5 (A-23-93)	01		10200601	1a1	312.5	39.2	0.064	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
5	031012ABI	4542.4	Corn Products International Inc	2046	0160	UTILITIES - BOILER #6 (A23-144)	01		10200601	1a1	600	16.8	0.0384	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
6	031012ABI	4542.4	Corn Products International Inc	2046	0233	UTILITIES - BOILER #7	01		10200601	1a1	240	30.5	0.087	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
7	031012ABI	4542.4	Corn Products International Inc	2046	0041	UTILITIES - BOILER #1 (A-23-92)	01		10200202	1c2	332.5	760.7	3.1979	COAL - BITUMINOUS	EXTERNAL COMBUSTION B	BITUMINOUS CO	PULVERIZED COAL: DRY BOTTOM
8	031012ABI	4542.4	Corn Products International Inc	2046	0042	UTILITIES - BOILER #2 (A-23-92)	01		10200202	1c2	332.5	796.9	3.2401	COAL - BITUMINOUS	EXTERNAL COMBUSTION B	BITUMINOUS CO	PULVERIZED COAL: DRY BOTTOM
9	031012ABI	4542.4	Corn Products International Inc	2046	0045	UTILITIES - BOILER #3 (A-23-93)	01		10200202	1c2	332.5	772.6	2.4953	COAL - BITUMINOUS	EXTERNAL COMBUSTION B	BITUMINOUS CO	PULVERIZED COAL: DRY BOTTOM
10	031045AAJ	316.1	Kimble Glass Inc		0006	GLASS MELTING FURNACE B	01		30501402	3	25	50.8	0.14				
11	031069AAI	1113.0	Saint-Gobain Containers Inc		0013	3 GLASS MELTING FURNACES (1, 2 AND 3)	01		30501402	3	120	681.2	1.87564	NATURAL GAS			
12	031081AEQ	286.5	Northwestern University	8221	0001	3 BC Boilers (#1, 2 and 3 - Central Utility Plant)	01		10300601	1a1	556	156.7	0.4436	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MMBTU/HR
13	031258ABR	516.7	Mittal Steel USA - Riverdale Inc	3312	0184	TUNNEL FURNACE	01		30390003	7b	123	44.1	0.1502	NATURAL GAS	PRIMARY METAL PRODUCT	PROCESS HEATE	NATURAL GAS
14	031600ADY	1338.7	Carmeuse Lime Inc	3274	0024	ROTARY KILN 4	01		30501605	5a	155.6	250.4	0.9868	PROPANE	MINERAL PRODUCTS	LIME MANUFACT	CALCIMATIC KILN
15	031600ADY	1338.7	Carmeuse Lime Inc	3274	0028	ROTARY KILN 5	01		30501604	5a	433.3	484.1	1.564	PROPANE	MINERAL PRODUCTS	LIME MANUFACT	CALCINING: ROTARY KILN
16	031600AIN	32962.1	Crawford Electric Generating Statio	4911	0013	Unit 7	01	Coal	10100226	8a	2342	873.9	2.746	COAL - SUBBITUMINO	EXTERNAL COMBUSTION B	SUBBITUMINOUS	PULVERIZED COAL: DRY BOTTOM (TANGENTIA
17	031600AIN	32962.1	Crawford Electric Generating Statio	4911	0016	Unit 8	01	Coal	10100226	8a	3556	1375.0	4.1789	COAL - SUBBITUMINO	EXTERNAL COMBUSTION B	SUBBITUMINOUS	PULVERIZED COAL: DRY BOTTOM (TANGENTIA
18	031600AMI	13414.4	Fisk Electric Generating Station	4911	0010	FISK UNIT #19	01	COAL FIRING	10100226	8a	2896	1125.6	3.8275	COAL - SUBBITUMINO	EXTERNAL COMBUSTION B	SUBBITUMINOUS	PULVERIZED COAL: DRY BOTTOM (TANGENTIA
19	031600CAO	221.5	Kraft Foods Global Inc	2052	0107	BOILER #5	01	NATURAL GAS	10200602	1a2	63.3	20.7	0.012	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	10-100 MMBTU/HR
20	031600DDJ	175.6	National Railroad Passenger Corp	4013	0001	BOILER #1	01	NATURAL GAS FIR	10200602	1a2	77.4	16.0	0	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	10-100 MMBTU/HR
21	031600FLT	204.3	University of Chicago	8221	0001	BOILERS 1-4	01	NATURAL GAS FIR	10200601	1a1	782	63.5	0.1142	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
22	031600FMX	114.3	Northwestern Memorial Hospital	8062	0002	5 Boilers	01	Natural gas combustio	10300602	1a2	126	31.8	0.0874	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	10-100 MMBTU/HR
23	031600FQP	202.5	Chicago - Dept of Aviation	4581	0003	8 HIGH TEMPERATURE WATER GENERATORS (HTWG-	01	NATURAL GAS CO	10200602	1a2	758.6	26.0	0.3708	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	10-100 MMBTU/HR
24	031817AAB	108.9	Loyola University Medical Center	8221	0017	BOILERS 2, 3 AND 4	01		10300602	1a2	154.9	20.6	0.0481	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	10-100 MMBTU/HR
25	031817AAL	292.7	VA Edward Hines Jr Hospital	8062	0004	BOILERS 1-4	01	NATURAL GAS	10300602	1a1	200	17.8	0.0231	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	10-100 MMBTU/HR
26	043802AAA	727.9	Argonne National Laboratory	8733	0001	Boiler #1	01	Natural Gas Combusti	10300601	1a1	106	25.2	0.082	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MMBTU/HR
27	043802AAA	727.9	Argonne National Laboratory	8733	0003	Boiler #3	01	Natural Gas Combusti	10300601	1a1	106	19.4	0	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MMBTU/HR
28	043802AAA	727.9	Argonne National Laboratory	8733	0004	Boiler #4	01	Natural Gas Combusti	10300601	1a1	106	19.0	0	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MMBTU/HR
29	043802AAA	727.9	Argonne National Laboratory	8733	0005	Boiler #5	04	Coal Firing	10300205	1c3	212	21.6	0	COAL - SUBBITUMINO	EXTERNAL COMBUSTION B	BITUMINOUS CO	PULVERIZED COAL: WET BOTTOM
30	063800AAC	628.1	Equistar Chemicals LP	2869	0025	ETHYLENE PLANT - STEAM SUPERHEATER	01		10200799	1a1	141	47.2	0.1294	OTHER GASEOUS FUEL	EXTERNAL COMBUSTION B	PROCESS GAS	> 100 MBTU/HR
31	063800AAC	628.1	Equistar Chemicals LP	2869	0026	ETHYLENE PLANT - 14 CRACKING FURNACES (101-114)	01		30600104	2a1	1277	357.3	0.9788	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
32	063800AAE	491.0	Akzo Nobel Surface Chemistry LL	2869	0033	STEAM BOILER J-090 (NEBRASKA)	03	PITCH FUEL FIRED	10201201	1e4	40.2	37.1	0.2271	OTHER	EXTERNAL COMBUSTION B	SOLID WASTE	SPECIFY WASTE MATERIAL IN COMMENTS
33	063800AAE	491.0	Akzo Nobel Surface Chemistry LL	2869	0017	DOWTHERM BOILER	02	PITCH FUEL FIRED	10201201	2c3	17	26.5	0.103	OTHER	EXTERNAL COMBUSTION B	SOLID WASTE	SPECIFY WASTE MATERIAL IN COMMENTS
34	063800AAM	243.8	Aux Sable Liquid Products	1321	0019	Heaters 1H101, 2H101, H301, H601, H602, 501A, 501B	01		39000699	2a1	859.3	156.1	0.4359	NATURAL GAS	IN-PROCESS FUEL USE	NATURAL GAS	GENERAL
35	089800AAH	711.8	Dial Corp	2841	0075	BOILERS #1 AND #2	01	NATURAL GAS	10200601	1a1	210	124.1	0.3475	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
36	097125AAA	582.3	Abbott Laboratories	2834	0858	BOILER #10 NC (CED)	01	NATURAL GAS	10200601	1a1	220	24.7	0.0761	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
37	097125AAA	582.3	Abbott Laboratories	2834	0070	BOILER #5NC (TT-16) (CED)	01	COAL FIRED	10100204	1e4	85	85.5	0.2898	COAL - BITUMINOUS	EXTERNAL COMBUSTION B	BITUMINOUS CO	SPREADER STOKER
38	097125AAA	582.3	Abbott Laboratories	2834	0242	BOILER #6 NC (TT-20) (CED)	01	COAL FIRED	10100204	1e4	85	77.1	0.2743	COAL - BITUMINOUS	EXTERNAL COMBUSTION B	BITUMINOUS CO	SPREADER STOKER
39	097190AAC	47103.0	Waukegan Electric Generating Statio	4911	0031	UNIT #6 BOILER	01	COAL FIRING	10100203	8a	1024	1627.3	5.9705	COAL - SUBBITUMINO	EXTERNAL COMBUSTION B	BITUMINOUS CO	CYCLONE FURNACE
40	097190AAC	47103.0	Waukegan Electric Generating Statio	4911	0033	UNIT #8 BOILER	01	COAL FIRING	10100226	8a	3271	1595.4	4.6723	COAL - SUBBITUMINO	EXTERNAL COMBUSTION B	SUBBITUMINOUS	PULVERIZED COAL: DRY BOTTOM (TANGENTIA
41	097190AAC	47103.0	Waukegan Electric Generating Statio	4911	0036	UNIT #7 BOILER	01	COAL FIRING	10100226	8a	2911	1397.9	4.2687	COAL - SUBBITUMINO	EXTERNAL COMBUSTION B	SUBBITUMINOUS	PULVERIZED COAL: DRY BOTTOM (TANGENTIA
42	097809AAD	1629.2	Abbott Laboratories	2834	0006	Boiler 4AP	01	Coal fired	10200204	1e4	83	147.8	0.4492	COAL - BITUMINOUS	EXTERNAL COMBUSTION B	BITUMINOUS CO	SPREADER STOKER
43	097809AAD	1629.2	Abbott Laboratories	2834	0103	Boiler #5AP	01	Coal fired	10200204	1e4	83	129.2	0.3739	COAL - BITUMINOUS	EXTERNAL COMBUSTION B	BITUMINOUS CO	SPREADER STOKER
44	097811AAC	826.8	Naval Training Center	9711	0011	BUILDING 11 BOILERS #5 AND #6	01	NATURAL GAS CO	10200601	1a1	680	94.0	0.0341	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
45	119010AAE	1916.7	Alton Steel Inc	3312	0033	14 INCH BILLET REHEAT FURNACE	01	GAS FIRED	30300933	7a	255	47.6	0.3174	NATURAL GAS	PRIMARY METAL PRODUCT	STEEL PRODUCT	REHEAT FURNACES
46	119020AAE	24289.8	Dynegy Midwest Generation Inc	4911	0001	BOILER 5 PULV DRY TANGENTIAL	01	COAL FIRING	10100202	8a	3920	1910.9	5.3293	COAL - SUBBITUMINO	EXTERNAL COMBUSTION B	BITUMINOUS CO	PULVERIZED COAL: DRY BOTTOM
47	119020AAE	24289.8	Dynegy Midwest Generation Inc	4911	0003	BLR 4 PULV DRY BTM TANGENTIAL	01	COAL FIRING	10100202	8a	1030	456.6	1.5082	COAL - SUBBITUMINO	EXTERNAL COMBUSTION B	BITUMINOUS CO	PULVERIZED COAL: DRY BOTTOM
48	119090AAA	13872.0	ConocoPhillips Co	2911	0080	UTILITY BOILER #15 (BLR-15)	02	RFG	10200701	1a1	360	106.9	0.2929	OTHER GASEOUS FUEL	EXTERNAL COMBUSTION B	PROCESS GAS	PETROLEUM REFINERY GAS
49	119090AAA	13872.0	ConocoPhillips Co	2911	0081	UTILITY BOILER #16 (BLR-16)	02	RFG	10200701	1a1	249	149.4	0.4093	OTHER GASEOUS FUEL	EXTERNAL COMBUSTION B	PROCESS GAS	PETROLEUM REFINERY GAS
50	119090AAA	13872.0	ConocoPhillips Co	2911	0082	UTILITY BOILER #17 (BLR-17)	02	RFG	10200701	1a1	700	125.2	0.3431	OTHER GASEOUS FUEL	EXTERNAL COMBUSTION B	PROCESS GAS	PETROLEUM REFINERY GAS
51	119090AAA	13872.0	ConocoPhillips Co	2911	0083	UTILITY BOILER #18 (BLR-18)	01	NATURAL GAS	10200601	1a1	249	86.8	0.2378	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
52	119090AAA	13872.0	ConocoPhillips Co	2911	0083	UTILITY BOILER #18 (BLR-18)	02	REFINERY FUEL G	10200701	1a1	249	30.0	0.0821	OTHER GASEOUS FUEL	EXTERNAL COMBUSTION B	PROCESS GAS	PETROLEUM REFINERY GAS
53	119090AAA	13872.0	ConocoPhillips Co	2911	0614	BOILER NO 5	01	NATURAL GAS CO	10200602	1a2	66	15.3	0.0419	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	10-100 MMBTU/HR
54	119090AAA	13872.0	ConocoPhillips Co	2911	0004	CAT REFORMER #1: FEED PREHEATER (HTR-CR1-H1)	02	RFG	30600106	2a1	165	130.8	0.3584	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
55	119090AAA	13872.0	ConocoPhillips Co	2911	0005	CAT REFORMER #1: FIRST INTERREACTOR HEATER (H	02	RFG	30600104	2a1	162	164.3	0.4502	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
56	119090AAA	13872.0	ConocoPhillips Co	2911	0014	HYDROCRACKING UNIT: FRACTIONATOR REBOILER (H	02	RFG	30600106	2a1	235	152.0	0.4164	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
57	119090AAA	13872.0	ConocoPhillips Co	2911	0018	BENZENE EXTRACTION UNIT #2 (HTR-BEU-HM2)	02	RFG	30600106	2a1	110	59.5	0.163	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
58	119090AAA	13872.0	ConocoPhillips Co	2911	0024	DISTILLING UNIT: HTR-DU1-F301	02	REFINERY GAS (RF	30600106	2a1	120	138.8	0.3803	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
59	119090AAA	13872.0	ConocoPhillips Co	2911	0025	DISTILLING UNIT: HTR-DU1-F302	01	RFG	30600106	2a1	200	226.9	0.6217	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
60	119090AAA	13872.0	ConocoPhillips Co	2911	0029	DISTILLING UNIT: WEST CRUDE HEATER (HTR-DU2-F2	02	REFINERY GAS (RF	30600104	2a1	230	221.7	0.6073	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
61	119090AAA	13872.0	ConocoPhillips Co	2911	0030	DISTILLING UNIT: EAST CRUDE HEATER (HTR-DU2-F20	01	RFG	30600106	2a1	230	226.6	0.6208	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
62	119090AAA	13872.0	ConocoPhillips Co	2911	0073	ALKYLATION UNIT: HTR-ALKY-HM2	02	RFG	30600106	2a1	110	76.6	0.2099	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
63	119090AAA	13872.0	ConocoPhillips Co	2911	0084	CAT REFORMER #2: CHARGE REHEATER (HTR-CR2-N)	01	RFG	30600106	2a1	137.5	65.4	0.1792	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
64	119090AAA	13872.0	ConocoPhillips Co	2911	0086	HEATER CR2-S (RFG FIRING)	01	FUEL COMBUSTIO	30600104	2a1	137.5	65.4	0.1792	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
65	119090AAA	13872.0	ConocoPhillips Co	2911	0091	CAT REFORMER #3: CHARGE HEATER (HTR-CR3-H4)	01	RFG	30600106	2a1	144.7	165.1	0.4524	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
66	119090AAA	13872.0	ConocoPhillips Co	2911	0092	CAT REFORMER #3: FIRST INTERREACTOR HEATER (H	02	RFG	30600106	2a1	141	136.8	0.3748	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
67	119090AAA	13872.0	ConocoPhillips Co	2911	0094	KEROSENE HYDROTREATER: KHT HEATER (HTR-KHT)	01	RFG	30600106	2a1	109	106.2	0.2909	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
68	119090AAA	13872.0	ConocoPhillips Co	2911	0617	DELAYED COKER UNIT HEATER H-20	02	REFINERY FUEL G	30600106	2a1	231	98.1	0.2688	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
69	119090AAA	13872.0	ConocoPhillips Co	2911	0623	NO.2 CRUDE UNIT HEATER H-24	01	NATURAL GAS CO	30600104	2a1	314	150.2	1.0018	NATURAL GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
70	119090AAA	13872.0	ConocoPhillips Co	2911	0006	CAT REFORMER #1: SECOND INTERREACTOR HEATER	02	RFG	30600104	2a2	78	27.8	0.0761	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
71	119090AAA	13872.0	ConocoPhillips Co	2911	0007	CAT REFORMER #1: STABILIZER REBOILER (HTR-CR1-H	02	RFG	30600106	2a2	100	16.7	0.0458	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
72	119090AAA	13872.0	ConocoPhillips Co	2911	0009	CAT REFORMER #1: THIRD INTERREACTOR HEATER (H	02	RFG	30600106	2a2	100	86.7	0.2375	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
73	119090AAA	13872.0	ConocoPhillips Co	2911	0017	BENZENE EXTRACTION UNIT #1 (HTR-BEU-HM1)	02	RFG	30600106	2a2	100	81.7	0.2239	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED

74	119090AAA	13872.0	ConocoPhillips Co	2911	0031	VACUUM FLASHER UNITS #1-3 (VF-1, -2, -3)	01		30600104	2a2	273	140.2	0.384	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
75	119090AAA	13872.0	ConocoPhillips Co	2911	0033	RECTIFIED ABSORPTION UNIT: REBOILER HEATER (HT	01	RFG	30600106	2a2	69	23.0	0.0629	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
76	119090AAA	13872.0	ConocoPhillips Co	2911	0036	CRACKED ABSORPTION UNIT (HTR-CAU-ROSTILL)	02	RFG AND RFP	30600106	2a2	95	30.0	0.0822	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
77	119090AAA	13872.0	ConocoPhillips Co	2911	0042	CO HEATER (HTRR-CCU1-CO)	01	RFG	30600104	2a2	17	91.9	0.2518	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
78	119090AAA	13872.0	ConocoPhillips Co	2911	0056	CO HEATER (HTRR-CCU2-CO)	01	RFG	30600104	2a2	80	82.1	0.2249	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
79	119090AAA	13872.0	ConocoPhillips Co	2911	0085	HYDRODESULFURIZATION UNIT #1: CHARGE HEATER	01	RFG	30600106	2a2	67.3	19.6	0.0536	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
80	119090AAA	13872.0	ConocoPhillips Co	2911	0088	HYDRODESULFURIZATION UNIT #2: CHARGE HEATER	01	RFG	30600106	2a2	81	26.2	0.0719	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
81	119090AAA	13872.0	ConocoPhillips Co	2911	0093	CAT REFORMER #3: SECOND INTERREACTOR HEATER	02	RFG	30600106	2a2	74	27.1	0.0742	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
82	119090AAA	13872.0	ConocoPhillips Co	2911	0154	VACUUM FLASHER #2 EAST HEATER (HTR-VF2-F205)	01	RFG	30600106	2a2	61	15.9	0.0436	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
83	119090AAA	13872.0	ConocoPhillips Co	2911	0155	VACUUM FLASHER #1: NORTH HEATER (HTR-VF-1-NOR	01		30600105	2a2	100	45.5	0.1247	NATURAL GAS	PETROLEUM INDUSTRY	PROCESS HEATE	NATURAL GAS-FIRED
84	119090AAA	13872.0	ConocoPhillips Co	2911	0156	VACUUM FLASHER #1 SOUTH HEATER (HTR-VF-1-SOU	01		30600105	2a2	100	50.9	0.1394	NATURAL GAS	PETROLEUM INDUSTRY	PROCESS HEATE	NATURAL GAS-FIRED
85	119813AAI	7044.1	US Steel Granite City	3312	0044	BOILER HOUSE 2 BOILER #11 - BLAST FURNACE DEPT	04	NATURAL GAS FIR	10200601	1a1	225	25.7	0.0654	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	< 100 MBTU HR
86	119813AAI	7044.1	US Steel Granite City	3312	0044	BOILER HOUSE 2: BOILER #11 - BLAST FURNACE DEPT	01	BLAST FURNACE G	10200704	1a1	225	31.7	0.0454	PROCESS GAS	EXTERNAL COMBUSTION B	PROCESS GAS	BLAST FURNACE GAS
87	119813AAI	7044.1	US Steel Granite City	3312	0048	BOILER HOUSE 2 BOILER #12 - BLAST FURNACE DEPT	04	NATURAL GAS FIR	10200601	1a1	225	24.8	0.0456	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	< 100 MBTU HR
88	119813AAI	7044.1	US Steel Granite City	3312	0048	BOILER HOUSE 2: BOILER #12 - BLAST FURNACE DEPT	01	BLAST FURNACE G	10200704	1a1	225	21.2	0.0436	PROCESS GAS	EXTERNAL COMBUSTION B	PROCESS GAS	BLAST FURNACE GAS
89	119813AAI	7044.1	US Steel Granite City	3312	0048	BOILER HOUSE 2: BOILER #12 - BLAST FURNACE DEPT	02	COKE OVEN GAS F	10200707	1a1	225	64.5	0.138	PROCESS GAS	EXTERNAL COMBUSTION B	PROCESS GAS	COKE OVEN GAS
90	119813AAI	7044.1	US Steel Granite City	3312	0041	BOILER HOUSE 1: BOILERS 1 TO 7	01	BLAST FURNACE G	10200704	1a2	60	66.0	0.1502	PROCESS GAS	EXTERNAL COMBUSTION B	PROCESS GAS	BLAST FURNACE GAS
91	119813AAI	7044.1	US Steel Granite City	3312	0041	BOILER HOUSE 1: BOILERS 1 TO 7	04	NATURAL GAS FIR	10200601	1a2	420	44.6	0.1538	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU HR
92	119813AAI	7044.1	US Steel Granite City	3312	0041	BOILER HOUSE 1 BOILERS 1 TO 7	02	COKE OVEN GAS F	10200707	1a2	559	134.2	0.4103	PROCESS GAS	EXTERNAL COMBUSTION B	PROCESS GAS	COKE OVEN GAS
93	119813AAI	7044.1	US Steel Granite City	3312	0042	BOILER HOUSE 1 - BOILERS 8 TO 10	04	NATURAL GAS FIR	10200602	1a2	60	19.1	0.0659	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	10-100 MMBTU/HR
94	119813AAI	7044.1	US Steel Granite City	3312	0042	BOILER HOUSE 1: BOILERS 8 TO 10	01	BLAST FURNACE G	10200704	1a2	80	28.3	0.0644	PROCESS GAS	EXTERNAL COMBUSTION B	PROCESS GAS	BLAST FURNACE GAS
95	119813AAI	7044.1	US Steel Granite City	3312	0042	BOILER HOUSE 1: BOILERS 8 TO 10	02	COKE OVEN GAS F	10200707	1a2	60	57.5	0.1758	PROCESS GAS	EXTERNAL COMBUSTION B	PROCESS GAS	COKE OVEN GAS
96	119813AAI	7044.1	US Steel Granite City	3312	0015	SLAB FURNACE #1	02	COKE OVEN GAS F	39000689	7a	321.8	84.9	0.4144	PROCESS GAS	IN-PROCESS FUEL USE	NATURAL GAS	GENERAL
97	119813AAI	7044.1	US Steel Granite City	3312	0015	SLAB FURNACE #1	01	NATURAL GAS FIR	39000689	7a	321.8	266.2	0.7086	NATURAL GAS	IN-PROCESS FUEL USE	NATURAL GAS	GENERAL
98	119813AAI	7044.1	US Steel Granite City	3312	0018	SLAB FURNACE #4	01	NATURAL GAS FIR	39000689	7a	495	113.8	0.9587	NATURAL GAS	IN-PROCESS FUEL USE	NATURAL GAS	GENERAL
99	119813AAI	7044.1	US Steel Granite City	3312	0122	SLAB FURNACE #2	02	COKE OVEN GAS F	39000689	7a	322	82.2	0.3938	PROCESS GAS	IN-PROCESS FUEL USE	NATURAL GAS	GENERAL
100	119813AAI	7044.1	US Steel Granite City	3312	0122	SLAB FURNACE #2	01	NATURAL GAS FIR	39000689	7a	322	149.2	0.6906	NATURAL GAS	IN-PROCESS FUEL USE	NATURAL GAS	GENERAL
101	119813AAI	7044.1	US Steel Granite City	3312	0123	SLAB FURNACE #3	02	COKE OVEN GAS F	39000689	7a	322	101.6	0.4321	PROCESS GAS	IN-PROCESS FUEL USE	NATURAL GAS	GENERAL
102	119813AAI	7044.1	US Steel Granite City	3312	0123	SLAB FURNACE #3	01	NATURAL GAS FIR	39000689	7a	322	162.8	0.7052	NATURAL GAS	IN-PROCESS FUEL USE	NATURAL GAS	GENERAL
103	157851AAA	4875.6	Dynegy Midwest Generation Inc	4911	0001	*BOILER #1	01	COAL FIRING	10100202	8a	5890	1106.9	3.627	COAL - SUBBITUMINOUS			
104	157851AAA	4875.6	Dynegy Midwest Generation Inc	4911	0002	*BOILER #2	01	COAL FIRING	10100202	8a	5900	1495.3	3.547	COAL - SUBBITUMINOUS			
105	157851AAA	4875.6	Dynegy Midwest Generation Inc	4911	0013	*BOILER #3	01	COAL FIRING	10100202	8a	5800	2271.6	6.624	COAL - SUBBITUMINOUS			
106	163045ADT	168.3	Elementis Pigments Inc	2816	0061	Erie City boiler	01	Natural gas	10200601	1a1	135	41.4	0.258	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
107	163121AAY	250.1	Environmental Management Corp	4961	0001	BOILERS #1, #2 AND #3	01	NATURAL GAS	10200601	1a1	393	22.4	0.0553	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
108	197090AAI	2877.3	CITGO Petroleum Corp	2911	0037	430B-1: Auxiliary boiler	01	Refinery fuel gas	10200701	1a1	396	120.5	0.3296	PROCESS GAS	EXTERNAL COMBUSTION B	PROCESS GAS	> 100 MBTU/HR
109	197090AAI	2877.3	CITGO Petroleum Corp	2911	0235	431B-20: North Plant Boiler	01		10200501	1b1	249	22.3	0.0398	DISTILLATE OIL #2	EXTERNAL COMBUSTION B	DISTILLATE OIL	GRADES 1 AND 2 OIL
110	197090AAI	2877.3	CITGO Petroleum Corp	2911	0003	111B-1A Atmospheric heater	01	Refinery fuel gas	30600104	2a1	376.5	46.4	0.1345	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
111	197090AAI	2877.3	CITGO Petroleum Corp	2911	0004	111B-1B: Atmospheric heater	01	Refinery fuel gas	30600104	2a1	376.5	47.2	0.1362	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
112	197090AAI	2877.3	CITGO Petroleum Corp	2911	0005	111B-2: Crude vacuum heater	01	REFINERY FUEL G	30600104	2a1	219.8	18.1	0.057	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
113	197090AAI	2877.3	CITGO Petroleum Corp	2911	0050	109B-62 Steam HC reformer heater	01		30600104	2a1	113.3	55.2	0.1751	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
114	197090AAI	2877.3	CITGO Petroleum Corp	2911	0070	123B-2. Feed preheater	01	REFINERY FUEL G	30600106	2a1	121.2	54.5	0.1428	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
115	197090AAI	2877.3	CITGO Petroleum Corp	2911	0011	113B-1: Coker 1 charge heater	01		30600104	2a2	88.8	16.0	0.0439	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
116	197090AAI	2877.3	CITGO Petroleum Corp	2911	0012	113B-3. Coker 1 charge heater	01		30600104	2a2	88.8	26.7	0.0721	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
117	197090AAI	2877.3	CITGO Petroleum Corp	2911	0019	116B-1: Charge heater and stabilizer reboiler	01		30600104	2a2	89.9	41.5	0.1196	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
118	197090AAI	2877.3	CITGO Petroleum Corp	2911	0021	118B-1: Hot oil heater	01		30600104	2a2	93.8	15.6	0.044	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
119	197090AAI	2877.3	CITGO Petroleum Corp	2911	0048	108B-41: Process heater	01		30600104	2a2	44	22.7	0.0614	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
120	197090AAI	2877.3	CITGO Petroleum Corp	2911	0064	113B-2: Coker 1 charge heater	01		30600106	2a2	88.8	16.4	0.045	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
121	197090AAI	2877.3	CITGO Petroleum Corp	2911	0066	116B-2: Interheater and naphtha stripper reboiler	01		30600106	2a2	84.2	24.9	0.0618	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
122	197090AAI	2877.3	CITGO Petroleum Corp	2911	0073	123B-5: Reheat furnace	01		30600106	2a2	42	17.5	0.0472	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
123	197090AAI	2877.3	CITGO Petroleum Corp	2911	0074	125B-1 and 125B-2 Feed heater and stripper reboil	01		30600106	2a2	100	32.0	0.0863	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
124	197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0002	AUX BOILER	03	On hot standby (when	30600104	1a1	600	35.6	0.1013	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	> 100 MBTU HR
125	197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0018	Crude unit heaters (#1B1A and #1B1B)	01	Gas fired	30600104	2a1	778	288.5	0.7786	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
126	197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0019	Crude unit vacuum heater	01	Refinery gas fired	30600106	2a1	277	117.5	0.3157	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
127	197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0021	Coker charge heaters (East and West)	01		10200701	2a1	732	123.3	0.3185	PROCESS GAS	EXTERNAL COMBUSTION B	PROCESS GAS	PETROLEUM REFINERY GAS
128	197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0025	Reformer charge heaters (2B3, 2B4, 2B5, 2B6)	01		30600106	2a1	680	97.6	0.2583	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
129	197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0028	Pretreat debut reboil 17-B-2	01		10200701	2a1	164	15.8	0.0454	PROCESS GAS	EXTERNAL COMBUSTION B	PROCESS GAS	PETROLEUM REFINERY GAS
130	197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0033	CHD react charge heater 3B1	01	Refinery gas	30600104	2a1	158	41.4	0.1183	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
131	197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0034	CHD strip reboiler 3B2	01		10200701	2a1	129	42.6	0.1063	PROCESS GAS	EXTERNAL COMBUSTION B	PROCESS GAS	PETROLEUM REFINERY GAS
132	197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0038	Alky isostrip reboiler heater 7B1	01	Refinery gas	10200701	2a1	171	34.1	0.1065	PROCESS GAS	EXTERNAL COMBUSTION B	PROCESS GAS	PETROLEUM REFINERY GAS
133	197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0113	Crude unit feed preheater 1-B3/13-B-4	01	Gas feed	30600106	2a1	240	30.7	0.0846	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
134	197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0038	Alky isostrip reboiler heater 7B1	02	Oil fired (ASO)	30600103	2b1	171	23.3	0.0698	RESIDUAL OIL #4	PETROLEUM INDUSTRY	PROCESS HEATE	OIL FIRED
135	197800AAD	198.2	Loders Croklaan USA	2079	0043	JOHNSTON BOILER	01		10200602	1a2	93.7	41.5	0.114	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	10-100 MMBTU/HR
136	197800ABZ	1056.4	Flint Hills Resources LP	2865	0021	2 BOILERS (CB-703, CB-704)	01		10200601	1a1	450	55.2	0.1628	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU HR
137	197800ABZ	1056.4	Flint Hills Resources LP	2865	0119	BOILER CB-706	01		10200601	1a1	370.2	17.8	0.0254	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU HR
138	197809AAC	227.0	Caterpillar Inc	3531	0004	Boiler #2	01	Natural gas combustio	10200601	1a1	112.6	16.1	0.0837	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
139	197809AAC	227.0	Caterpillar Inc	3531	0005	Boiler #3	01	Natural gas combustio	10200601	1a1	175	40.0	0.079	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
140	197809AAO	60970.8	Midwest Generation LLC	4911	0009	Joliet 9. Unit 6 cyclone boiler	01	Coal	10100203	8a	2886	5418.6	16.9076	COAL - SUBBITUMINO	EXTERNAL COMBUSTION B	BITUMINOUS CO	CYCLONE FURNACE
141	197809AAO	60970.8	Midwest Generation LLC	4911	0031	Joliet 29. Unit 7 Boilers 71 and 72	01	Coal	10100202	8a	4558	1760.7	6.0416	COAL - SUBBITUMINO	EXTERNAL COMBUSTION B	BITUMINOUS CO	PULVERIZED COAL DRY BOTTOM
142	197809AAO	60970.8	Midwest Generation LLC	4911	0033	Joliet 29. Unit 8 Boilers 81 and 82	01	Coal	10100202	8a	3193	1879.2	5.9909	COAL - SUBBITUMINO	EXTERNAL COMBUSTION B	BITUMINOUS CO	PULVERIZED COAL DRY BOTTOM
143	197810AAK	18014.4	Will County Electric Generating Stat	4911	0010	UNIT #1 BOILER CYCLONE	02	COAL FIRING	10100223	8a	1728	2679.0	9.5894	COAL - SUBBITUMINO	EXTERNAL COMBUSTION B	SUBBITUMINOUS	CYCLONE FURNACE
144	197810AAK	18014.4	Will County Electric Generating Stat	4911	0012	UNIT #2 BOILER CYCLONE	02	COAL FIRED	10100223	8a	1712	2531.0	9.1506	COAL - SUBBITUMINO	EXTERNAL COMBUSTION B	SUBBITUMINOUS	CYCLONE FURNACE
145	197810AAK	18014.4	Will County Electric Generating Stat	4911	0014	UNIT #3 BOILER PULV DRY BOTTOM - TANGENTIALY	02	COAL FIRED	10100222	8a	2709	873.1	2.7744	COAL - SUBBITUMINO	EXTERNAL COMBUSTION B	SUBBITUMINOUS	PULVERIZED COAL DRY BOTTOM
146	197810AAK	18014.4	Will County Electric Generating Stat	4911	0016	UNIT #4 BOILER PULV DRY BOTTOM - TANGENTIALY	02	COAL FIRED	10100222	8a	5016	1690.8	6.0994	COAL - SUBBITUMINO	EXTERNAL COMBUSTION B	SUBBITUMINOUS	PULVERIZED COAL DRY BOTTOM
						All Sources in Chicago and Metro-East NAAs, Total					**90419**	**44625**	**143**				

Table E-1: Boilers Subject to NOx SIP Call Regulations (>250 mmBtu/hour)

Mydocument/TSD/NOx RACT-Attachments.xls

Boilers > 250 mmBtu/hour in Chicago NAA

Facility ID	Source PTE TPY NOx	Facility Name	SIC	Emission Unit ID	Emission Point Description	Mode ID	Mode Description	SCC #	Emission Unit category	Heat Input Capacity mmbtu/hr	2005 NOx Emissions tpy	Unit Typical Ozone Season NOx tons/day	Fuel	descr1	descr3	descr4
Industrial Boilers >250 mmBtu/hour in Chicago NAA																
031012ABI	4542.4	Corn Products International In	2046	0046	UTILITIES - BOILER #5 (A-23-93)	01		10200601	1a1	312.5	39.2	0.064	NATURAL GA	EXTERNAL C	NATURAL GA	> 100 MBTU/HR
031012ABI	4542.4	Corn Products International In	2046	0160	UTILITIES - BOILER #6 (A23-144)	01		10200601	1a1	600	16.8	0.0384	NATURAL GA	EXTERNAL C	NATURAL GA	> 100 MBTU/HR
097811AAC	826.8	Naval Training Center	9711	0011	BUILDING 11, BOILERS #5 AND #6	01	NATURAL GAS COM	10200601	1a1	680	94.0	0.0341	NATURAL GA	EXTERNAL C	NATURAL GA	> 100 MBTU/HR
197090AAI	2877.3	CITGO Petroleum Corp	2911	0037	430B-1 Auxiliary boiler	01	Refinery fuel gas	10200701	1a1	396	120.5	0.3296	PROCESS GA	EXTERNAL C	PROCESS GA	> 100 MBTU/HR
197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0002	AUX BOILER	03	On hot standby (when o	30600104	1a1	600	35.6	0.1013	PROCESS GA	PETROLEUM	PROCESS HE	> 100 MBTU/HR
197800ABZ	1056.4	Flint Hills Resources LP	2865	0119	BOILER CB-706	01		10200601	1a1	370.2	17.8	0.0254	NATURAL GA	EXTERNAL C	NATURAL GA	> 100 MBTU/HR
031012ABI	4542.4	Corn Products International In	2046	0041	UTILITIES - BOILER #1 (A-23-92)	01		10200202	1e2	332.5	760.7	3.1979	COAL - BITU	EXTERNAL C	BITUMINOUS	PULVERIZED COAL DRY BOTTOM
031012ABI	4542.4	Corn Products International In	2046	0042	UTILITIES - BOILER #2 (A-23-92)	01		10200202	1e2	332.5	796.9	3.2401	COAL - BITU	EXTERNAL C	BITUMINOUS	PULVERIZED COAL DRY BOTTOM
031012ABI	4542.4	Corn Products International In	2046	0045	UTILITIES - BOILER #3 (A-23-93)	01		10200202	1e2	332.5	772.6	2.4953	COAL - BITU	EXTERNAL C	BITUMINOUS	PULVERIZED COAL DRY BOTTOM
EGU Boilers >250 mmBtu/hour in Chicago NAA																
031600AIN	32962.1	Crawford Electric Generating	4911	0013	Unit 7	01	Coal	10100226	8a	2342	873.9	2.746	COAL - SUBB	EXTERNAL C	SUBBITUMIN	PULVERIZED COAL DRY BOTTOM (TANGENTIAL)
031600AIN	32962.1	Crawford Electric Generating	4911	0016	Unit 8	01	Coal	10100226	8a	3556	1375.0	4.1789	COAL - SUBB	EXTERNAL C	SUBBITUMIN	PULVERIZED COAL DRY BOTTOM (TANGENTIAL)
031600AMI	13414.4	Fisk Electric Generating Static	4911	0010	FISK UNIT #19	01	COAL FIRING	10100226	8a	2896	1125.6	3.8275	COAL - SUBB	EXTERNAL C	SUBBITUMIN	PULVERIZED COAL DRY BOTTOM (TANGENTIAL)
097190AAC	47103.0	Waukegan Electric Generating	4911	0031	UNIT #6 BOILER	01	COAL FIRING	10100203	8a	1024	1627.3	5.9705	COAL - SUBB	EXTERNAL C	BITUMINOUS	CYCLONE FURNACE
097190AAC	47103.0	Waukegan Electric Generating	4911	0033	UNIT #8 BOILER	01	COAL FIRING	10100226	8a	3271	1595.4	4.6723	COAL - SUBB	EXTERNAL C	SUBBITUMIN	PULVERIZED COAL DRY BOTTOM (TANGENTIAL)
097190AAC	47103.0	Waukegan Electric Generating	4911	0036	UNIT #7 BOILER	01	COAL FIRING	10100226	8a	2911	1397.9	4.2667	COAL - SUBB	EXTERNAL C	SUBBITUMIN	PULVERIZED COAL DRY BOTTOM (TANGENTIAL)
197809AAO	60970.8	Midwest Generation LLC	4911	0009	Joliet 9 Unit 6 cyclone boiler	01	Coal	10100203	8a	2886	5418.6	16.9076	COAL - SUBB	EXTERNAL C	BITUMINOUS	CYCLONE FURNACE
197809AAO	60970.8	Midwest Generation LLC	4911	0031	Joliet 29 Unit 7 Boilers 71 and 72	01	Coal	10100202	8a	4558	1760.7	6.0416	COAL - SUBB	EXTERNAL C	BITUMINOUS	PULVERIZED COAL DRY BOTTOM
197809AAO	60970.8	Midwest Generation LLC	4911	0033	Joliet 29 Unit 8 Boilers 81 and 82	01	Coal	10100202	8a	3193	1879.2	5.9909	COAL - SUBB	EXTERNAL C	BITUMINOUS	PULVERIZED COAL DRY BOTTOM
197810AAK	18014.4	Will County Electric Generatin	4911	0010	UNIT #1 BOILER CYCLONE	02	COAL FIRING	10100223	8a	1728	2679.0	9.5894	COAL - SUBB	EXTERNAL C	SUBBITUMIN	CYCLONE FURNACE
197810AAK	18014.4	Will County Electric Generati	4911	0012	UNIT #2 BOILER CYCLONE	02	COAL FIRED	10100223	8a	1712	2531.0	9.1506	COAL - SUBB	EXTERNAL C	SUBBITUMIN	CYCLONE FURNACE
197810AAK	18014.4	Will County Electric Generati	4911	0014	UNIT #3 BOILER PULV DRY BOTTOM - TA	02	COAL FIRED	10100222	8a	2709	873.1	2.7744	COAL - SUBB	EXTERNAL C	SUBBITUMIN	PULVERIZED COAL DRY BOTTOM
197810AAK	18014.4	Will County Electric Generati	4911	0016	UNIT #4 BOILER PULV DRY BOTTOM - TA	02	COAL FIRED	10100222	8a	5016	1690.8	6.0994	COAL - SUBB	EXTERNAL C	SUBBITUMIN	PULVERIZED COAL DRY BOTTOM

Boilers > 250 mmBtu/hour in Metro-East NAA

Industrial Boilers >250 mmBtu/hour in Metro-East NAA																
119090AAA	13872.0	ConocoPhillips Co	2911	0080	UTILITY BOILER #15 (BLR-15)	02	RFG	10200701	1a1	360	106.9	0.2929	OTHER GASE	EXTERNAL C	PROCESS GA	PETROLEUM REFINERY GAS
119090AAA	13872.0	ConocoPhillips Co	2911	0082	UTILITY BOILER #17 (BLR-17)	02	RFG	10200701	1a1	700	125.2	0.3431	OTHER GASE	EXTERNAL C	PROCESS GA	PETROLEUM REFINERY GAS
EGU Boilers >250 mmBtu/hour in Metro-East NAA																
119020AAE	24289.8	Dynegy Midwest Generation I	4911	0001	BOILER 5 PULV DRY TANGENTIAL	01	COAL FIRING	10100202	8a	3920	1910.9	5.3293	COAL - SUBB	EXTERNAL C	BITUMINOUS	PULVERIZED COAL DRY BOTTOM
119020AAE	24289.8	Dynegy Midwest Generation I	4911	0003	BLR 4 PULV DRY BTM TANGENTIAL	01	COAL FIRING	10100202	8a	1030	456.6	1.5082	COAL - SUBB	EXTERNAL C	BITUMINOUS	PULVERIZED COAL DRY BOTTOM
157851AAA	4875.6	Dynegy Midwest Generation I	4911	0001	BOILER #1	01	COAL FIRING	10100202	8a	5890	1106.9	3.627	COAL - SUBBITUMINOUS			
157851AAA	4875.6	Dynegy Midwest Generation I	4911	0002	BOILER #2	01	COAL FIRING	10100202	8a	5900	1495.3	3.547	COAL - SUBBITUMINOUS			
157851AAA	4875.6	Dynegy Midwest Generation I	4911	0013	BOILER #3	01	COAL FIRING	10100202	8a	5800	2271.6	6.624	COAL - SUBBITUMINOUS			

Table F-1: NOx Reductions from the Application of NOx RACT in Chicago NAA

Mydocument/TSD/NOx RACT-Attachments.xls

Facility ID	Source PTE TPY NOx	Facility Name	SIC	Emission Unit ID	Emission Point Description	Mode ID	Mode Description	SCC #	Emission Unit category	Heat Input Capacity mmbtu/hr	2005 NOx Emissions tpy	Estimated NOx RACT Reduction, %	Estimated Controlled NOx tpy	Estimated Nox Reduction Tons	Unit Typical Ozone Season NOx tons/day	Ozone Season Controlled NOx, TPD	Ozone season NOx Reduction, TPD	Fuel	descr1	descr3	descr4
031003ADA	516.7	Alsip Paper Condominium Assn	4931	0004	BOILERS #1 AND #2	01		10200601	1a1	310	173.1	69.2%	53.3	119.85	0.2184	0.07	0.151	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
031012AAO	139.6	Nalco Co	2899	0049	BOILER #1	01	NATURAL GAS CO	10200601	1a1	114.6	17.9	69.2%	5.5	12.41	0.0656	0.02	0.05	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
031012AAO	139.6	Nalco Co	2899	0061	BOILER #2	01	NATURAL GAS CO	10200601	1a1	124	42.3	69.2%	13.0	29.26	0.2875	0.09	0.20	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
031012ABI	4542.4	Corn Products International Inc	2046	0046	UTILITIES - BOILER #5 (A-23-93)	01		10200601	1a1	312.5	39.2	69.2%	12.0	27.11	0.084	0.02	0.04	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
031012ABI	4542.4	Corn Products International Inc	2046	0160	UTILITIES - BOILER #6 (A23-144)	01		10200601	1a1	600	16.8	69.2%	5.2	11.66	0.0384	0.01	0.03	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
031012ABI	4542.4	Corn Products International Inc	2046	0233	UTILITIES - BOILER #7	01		10200601	1a1	240	30.5	69.2%	9.4	21.09	0.087	0.03	0.06	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
031081ABQ	286.5	Northwestern University	8221	0001	3 EC Boilers (#1, 2 and 3 - Central Utility Plant)	01		10300601	1a1	556	156.7	69.2%	48.2	108.46	0.4438	0.14	0.31	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MMBTU/HR
031600FLT	204.3	University of Chicago	8221	0003	BOILERS 1-4	01	NATURAL GAS FIR	10200601	1a1	792	63.5	69.2%	19.5	43.94	0.1142	0.04	0.08	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
031817AAL	292.7	VA Edward Hines Jr Hospital	8062	0004	BOILERS 1-4	01	NATURAL GAS	10300602	1a1	200	17.8	69.2%	5.5	12.35	0.0231	0.01	0.02	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	10-100 MMBTU/HR
043802AAA	727.9	Argonne National Laboratory	8733	0001	Boiler #1	01	Natural Gas Combust	10300601	1a1	106	25.2	69.2%	7.8	17.47	0.082	0.03	0.06	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MMBTU/HR
043802AAA	727.9	Argonne National Laboratory	8733	0003	Boiler #3	01	Natural Gas Combust	10300601	1a1	106	19.4	69.2%	6.0	13.42	0	0.00	0.00	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MMBTU/HR
043802AAA	727.9	Argonne National Laboratory	8733	0004	Boiler #4	01	Natural Gas Combust	10300601	1a1	106	19.0	69.2%	5.8	13.15	0	0.00	0.00	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MMBTU/HR
063800AAC	628.1	Equistar Chemicals LP	2869	0025	ETHYLENE PLANT - STEAM SUPERHEATER	01		10200799	1a1	141	47.2	69.2%	14.5	32.69	0.1294	0.04	0.09	OTHER GASEOUS FUEL	EXTERNAL COMBUSTION B	PROCESS GAS	> 100 MBTU/HR
089800AAH	711.8	Dial Corp	2841	0075	BOILERS #1 AND #2	01	NATURAL GAS	10200601	1a1	210	124.1	69.2%	38.2	85.89	0.3475	0.11	0.24	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
097125AAA	542.3	Abbott Laboratories	2834	0858	BOILER #10 NC (CED)	01	NATURAL GAS	10200601	1a1	220	24.7	69.2%	7.6	17.10	0.0761	0.02	0.06	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
097811AAC	126.8	Naval Training Center	9711	0011	BUILDING 11 BOILERS #5 AND #6	01	NATURAL GAS CO	10200601	1a1	680	94.0	69.2%	28.9	65.08	0.0341	0.01	0.02	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
197090AAI	2877.3	CITGO Petroleum Corp	2911	0037	430B-1 Auxiliary boiler	01	Refinery fuel gas	10200701	1a1	396	120.5	69.2%	37.1	83.42	0.3298	0.10	0.23	PROCESS GAS	EXTERNAL COMBUSTION B	PROCESS GAS	> 100 MBTU/HR
197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0002	AUX BOILER	03	On hot standby (wher	30600104	1a1	600	35.6	69.2%	11.0	24.65	0.1013	0.03	0.07	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	> 100 MBTU/HR
197800ABZ	1056.4	Flint Hills Resources LP	2865	0021	2 BOILERS (CB-703, CB-704)	01		10200601	1a1	450	55.2	69.2%	17.0	38.24	0.1628	0.05	0.11	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
197800ABZ	1056.4	Flint Hills Resources LP	2865	0119	BOILER CB-706	01		10200601	1a1	170.2	17.8	69.2%	5.5	12.30	0.0254	0.01	0.02	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
197809AAC	227.0	Caterpillar Inc	3531	0004	Boiler #2	01	Natural gas combustio	10200601	1a1	112.6	16.1	69.2%	5.0	11.13	0.0837	0.01	0.06	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
197809AAC	227.0	Caterpillar Inc	3531	0006	Boiler #3	01	Natural gas combustio	10200601	1a1	175	40.0	69.2%	12.3	27.66	0.079	0.02	0.05	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
					Gaseous Fuel-fired Boilers >100 mmBtu/hr, Total					**6911.9**	**1196.5**	69.2%	**368.2**	**828.3**	**2.79**	**0.86**	1.93				
031600CAO	221.5	Kraft Foods Global Inc	2062	0107	BOILER #5	01	NATURAL GAS	10200602	1a2	63.3	20.7	15.0%	17.6	3.11	0.012	0.01	0.00	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	10-100 MMBTU/HR
031600DDJ	175.6	National Railroad Passenger Corp	4013	0001	BOILER #1	01	NATURAL GAS FIR	10200602	1a2	77.4	16.0	15.0%	13.6	2.40	0	0.00	0.00	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	10-100 MMBTU/HR
197800AAD	198.2	Loders Croklaan USA	2079	0043	JOHNSTON BOILER	01		10200602	1a2	93.7	41.5	15.0%	35.3	6.23	0.114	0.10	0.02	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	10-100 MMBTU/HR
031600FMX	114.3	Northwestern Memorial Hospital	8062	0002	5 Boilers	01	Natural gas combustio	10300602	1a2	126	31.8	15.0%	27.0	4.77	0.0874	0.07	0.01	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	10-100 MMBTU/HR
031600FQP	202.5	Chicago - Dept of Aviation	4581	0003	8 HIGH TEMPERATURE WATER GENERATORS (HTWG-#	01	NATURAL GAS CO	10200602	1a2	758.6	26.0	15.0%	22.1	3.89	0.3708	0.32	0.06	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	10-100 MMBTU/HR
031817AAB	108.9	Loyola University Medical Center	8221	0017	BOILERS 2, 3 AND 4	01		10300602	1a2	154.9	20.6	15.0%	17.5	3.09	0.0481	0.04	0.01	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	10-100 MMBTU/HR
					Gaseous fuel-fired Boilers < =100 mmBtu/hr, Total					**1273.9**	**156.6**	15.0%	**133.1**	**23.5**	**0.63**	**0.54**	**0.09**				
197090AAI	2877.3	CITGO Petroleum Corp	2911	0235	431B-20 North Plant Boiler	01		10200501	1b1	249	22.3	52.4%	10.6	11.69	0.0388	0.02	0.02	DISTILLATE OIL #2	EXTERNAL COMBUSTION B	DISTILLATE OIL	GRADES 1 AND 2 OIL
					Dist. oil Boilers >100 mmBtu/hr, Total					249	**22.3**	**52.4%**	**10.6**	**11.7**	0.040	0.02	0.02				
031012ABI	4542.4	Corn Products International Inc	2046	0041	UTILITIES - BOILER #1 (A-23-92)	01		10200202	1c2	332.5	760.7	73.9%	198.4	562.26	3.1970	0.83	2.36	COAL - BITUMINOUS	EXTERNAL COMBUSTION B	BITUMINOUS CO	PULVERIZED COAL DRY BOTTOM
031012ABI	4542.4	Corn Products International Inc	2046	0042	UTILITIES - BOILER #2 (A-23-92)	01		10200202	1c2	332.5	796.9	73.9%	207.9	588.98	3.2401	0.85	2.39	COAL - BITUMINOUS	EXTERNAL COMBUSTION B	BITUMINOUS CO	PULVERIZED COAL DRY BOTTOM
031012ABI	4542.4	Corn Products International Inc	2046	0045	UTILITIES - BOILER #3 (A-23-93)	01		10200202	1c2	332.5	772.6	73.9%	201.6	571.08	2.4853	0.65	1.84	COAL - BITUMINOUS	EXTERNAL COMBUSTION B	BITUMINOUS CO	PULVERIZED COAL DRY BOTTOM
					Solid Fuel Boilers >250 mmbtu/hr, Total					**997.5**	**2330.2**	73.9%	**607.9**	**1722.3**	**8.93**	**2.33**	**6.60**				
043802AAA	727.9	Argonne National Laboratory	8733	0005	Boiler #5	04	Coal Firing	10100205	1c3	212	21.6	63.8%	7.8	13.8	0	0.00	0.00	COAL - SUBBITUMINOU	EXTERNAL COMBUSTION B	BITUMINOUS CO	PULVERIZED COAL WET BOTTOM
					Solid Fuel <=250, >100 mmbtu/hr, Total					212	**21.6**	**63.8%**	**7.8**	**13.8**	**0.0**	**0.0**	**0.0**				
063800AAE	491.0	Akzo Nobel Surface Chemistry LLC	2869	0031	STEAM BOILER J-090 (NEBRASKA)	03	PITCH FUEL FIRED	10201201	1c4	40.2	37.1	15.0%	31.6	5.57	0.2271	0.19	0.03	OTHER	EXTERNAL COMBUSTION B	SOLID WASTE	SPECIFY WASTE MATERIAL IN COMMENTS
097125AAA	512.3	Abbott Laboratories	2834	0070	BOILER #5NC (TT-16) (CED)	01	COAL FIRED	10100204	1c4	85	85.5	15.0%	72.7	12.83	0.2898	0.25	0.04	COAL - BITUMINOUS	EXTERNAL COMBUSTION B	BITUMINOUS CO	SPREADER STOKER
097125AAA	512.3	Abbott Laboratories	2834	0242	BOILER #6 NC (TT-20) (CED)	01	COAL FIRED	10100204	1c4	85	77.1	15.0%	65.5	11.56	0.2743	0.23	0.04	COAL - BITUMINOUS	EXTERNAL COMBUSTION B	BITUMINOUS CO	SPREADER STOKER
097809AAD	1629.2	Abbott Laboratories	2834	0006	Boiler 4AP	01	Coal fired	10200204	1c4	83	147.8	15.0%	125.6	22.17	0.4482	0.38	0.07	COAL - BITUMINOUS	EXTERNAL COMBUSTION B	BITUMINOUS CO	SPREADER STOKER
097809AAD	1629.2	Abbott Laboratories	2834	0103	Boiler #5AP	01	Coal fired	10200204	1c4	83	129.2	15.0%	109.8	19.38	0.3738	0.32	0.06	COAL - BITUMINOUS	EXTERNAL COMBUSTION B	BITUMINOUS CO	SPREADER STOKER
					Solid Fuel Boilers <=100 mmbtu/hr, Total					376.2	**476.7**	15.0%	**405.2**	**71.5**	**1.63**	**1.37**	**0.24**				
063800AAC	628.1	Equistar Chemicals LP	2869	0026	ETHYLENE PLANT - 14 CRACKING FURNACES (101-114)	01		30600104	2a1	1277	357.3	28.6%	255.2	102.07	0.9788	0.70	0.28	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
063800AAM	243.8	Aux Sable Liquid Products	1321	0019	Heaters 1H101, 2H101, H301, H601, H602, 501A, 501B	01		39000699	2a1	859.3	156.1	28.6%	111.5	44.59	0.4350	0.31	0.12	NATURAL GAS	IN-PROCESS FUEL USE	NATURAL GAS	GENERAL
197090AAI	2877.3	CITGO Petroleum Corp	2911	0001	111B-1A Atmospheric heater	01	Refinery fuel gas	30600104	2a1	376.5	46.4	28.6%	33.1	13.25	0.1345	0.10	0.04	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
197090AAI	2877.3	CITGO Petroleum Corp	2911	0004	111B-1B Atmospheric heater	01	Refinery fuel gas	30600104	2a1	376.5	47.2	28.6%	33.7	13.47	0.1382	0.10	0.04	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
197090AAI	2877.3	CITGO Petroleum Corp	2911	0005	111B-2 Crude vacuum heater	01	REFINERY FUEL G	30600104	2a1	219.8	18.1	28.6%	12.9	5.17	0.057	0.04	0.02	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
197090AAI	2877.3	CITGO Petroleum Corp	2911	0050	109B-62 Steam HC reformer heater	01		30600104	2a1	113.3	55.2	28.6%	39.5	15.78	0.1751	0.13	0.05	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
197090AAI	2877.3	CITGO Petroleum Corp	2911	0070	121B-2 Feed preheater	01	REFINERY FUEL G	30600106	2a1	121.2	54.5	28.6%	38.9	15.56	0.1428	0.10	0.04	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0018	Crude unit heaters (#1B1A and #1B1B)	01	Gas fired	30600104	2a1	778	288.5	28.6%	206.0	82.42	0.7786	0.56	0.22	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0019	Crude unit vacuum heater	01	Refinery gas fired	30600106	2a1	277	117.5	28.6%	83.9	33.59	0.3157	0.23	0.09	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0021	Coker charge heaters (East and West)	01		10200701	2a1	792	123.3	28.6%	88.1	35.23	0.3185	0.23	0.09	PROCESS GAS	EXTERNAL COMBUSTION B	PROCESS GAS	PETROLEUM REFINERY GAS
197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0025	Reformer charge heaters (2B3, 2B4, 2B5, 2B6)	01		30600106	2a1	680	97.6	28.6%	69.7	27.89	0.2583	0.19	0.07	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0028	Pretreat debut reboil 17-B-2	01		10200701	2a1	164	15.8	28.6%	11.3	4.50	0.0454	0.03	0.01	PROCESS GAS	EXTERNAL COMBUSTION B	PROCESS GAS	PETROLEUM REFINERY GAS
197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0033	CHD react charge heater 3B1	01	Refinery gas	30600104	2a1	158	41.4	28.6%	29.6	11.83	0.1163	0.08	0.03	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0034	CHD strip reboiler 3B2	01		10200701	2a1	129	42.6	28.6%	30.4	12.16	0.1083	0.08	0.03	PROCESS GAS	EXTERNAL COMBUSTION B	PROCESS GAS	PETROLEUM REFINERY GAS
197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0038	Alky isostrip reboiler heater 7B1	01	Refinery gas	10200701	2a1	171	34.1	28.6%	24.3	9.73	0.1085	0.08	0.03	PROCESS GAS	EXTERNAL COMBUSTION B	PROCESS GAS	PETROLEUM REFINERY GAS
197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0113	Crude unit feed preheater 1-B3/13-B-4	01	Gas fired	30600106	2a1	240	30.7	28.6%	21.9	8.77	0.0846	0.06	0.02	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
					Process Htrs Gas fired >100 mmBtu/hr, Total					**6672.6**	**1526.0**	28.6%	**1090.0**	**434.0**	**4.19**	**2.99**	**1.20**				
197090AAI	2877.3	CITGO Petroleum Corp	2911	0011	113B-1 Coker 1 charge heater	01		30600104	2a2	88.8	16.0	15.0%	13.6	2.40	0.0438	0.04	0.01	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
197090AAI	2877.3	CITGO Petroleum Corp	2911	0012	113B-3 Coker 1 charge heater	01		30600104	2a2	88.8	26.7	15.0%	22.7	4.00	0.0721	0.06	0.01	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
197090AAI	2877.3	CITGO Petroleum Corp	2911	0019	116B-1 Charge heater and stabilizer reboiler	01		30600104	2a2	89.9	41.5	15.0%	35.3	6.23	0.1198	0.10	0.02	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
197090AAI	2877.3	CITGO Petroleum Corp	2911	0021	118B-1 Hot oil heater	01		30600104	2a2	93.8	15.6	15.0%	13.3	2.35	0.044	0.04	0.01	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
197090AAI	2877.3	CITGO Petroleum Corp	2911	0048	108B-41 Process heater	01		30600104	2a2	44	22.7	15.0%	19.3	3.41	0.0814	0.05	0.01	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
197090AAI	2877.3	CITGO Petroleum Corp	2911	0064	113B-2 Coker 1 charge heater	01		30600106	2a2	88.5	16.4	15.0%	13.9	2.46	0.045	0.04	0.01	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
197090AAI	2877.3	CITGO Petroleum Corp	2911	0066	116B-2 Interheater and naphtha stripper reboiler	01		30600106	2a2	84.2	24.9	15.0%	21.1	3.73	0.0816	0.07	0.01	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
197090AAI	2877.3	CITGO Petroleum Corp	2911	0073	123B-3 Reboil furnace	01		30600106	2a2	42	17.5	15.0%	14.9	2.63	0.0472	0.04	0.01	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
197090AAI	2877.3	CITGO Petroleum Corp	2911	0074	125B-1 and 125B-2 Feed heater and stripper reboil	01		30600106	2a2	100	32.0	15.0%	27.2	4.80	0.0863	0.07	0.01	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
					Process Htrs Gas-fired< =100 mmBtu/hr, Total					**720.3**	**213.3**	15.0%	**181.3**	**32.0**	**0.60**	**0.51**	**0.09**				
197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0038	Alky isostrip reboiler heater 7B1	02	Oil fired (ASO)	30600103	2b1	171	23.3	76.2%	5.5	17.74	0.0698	0.02	0.05	RESIDUAL OIL #4	PETROLEUM INDUSTRY	PROCESS HEATE	OIL FIRED
					Process Htrs, Residual Oil-fired, >100 mmBtu/hr, Total					171	**23.3**	**76.2%**	**5.5**	**17.7**	**0.07**	**0.02**	**0.05**				
063800AAE	491.0	Akzo Nobel Surface Chemistry LLC	2869	0017	DOWTHERM BOILER	02	PITCH FUEL FIRED	10201201	2c1	17	26.5	15.0%	22.5	3.97	0.103	0.09	0.02	OTHER	EXTERNAL COMBUSTION B	SOLID WASTE	SPECIFY WASTE MATERIAL IN COMMENTS
					Process Htrs, Other Oil-fired,100 mmBtu/hr, Total					17	**26.5**		**22.5**	**4.0**	**0.10**	**0.09**	**0.01**				
031045AAJ	316.1	Kimble Glass Inc		0006	GLASS MELTING FURNACE B	01		30501402	3	25	50.8	50.0%	25.4	25.38	0.14	0.07	0.07				
031069AAI	1113.0	Saint-Gobain Containers Inc		0013	3 GLASS MELTING FURNACES (1, 2 AND 3)	01		30501402	3	120	681.2	50.0%	340.6	340.58	1.87584	0.94	0.94	NATURAL GAS			
					Glass melting Furnaces, Total					145	**731.9**	**50.0%**	**366.0**	**366.0**	**2.02**	**1.01**	**1.01**				
031600ADY	1338.7	Carmeuse Lime Inc	3274	0024	ROTARY KILN 4	01		30501605	5a	155.6	250.4	30.0%	175.2	75.11	0.9888	0.69	0.30	PROPANE	MINERAL PRODUCTS	LIME MANUFACT	CALCIMATIC KILN
031600ADY	1338.7	Carmeuse Lime Inc	3274	0029	ROTARY KILN 5	01		30501604	5a	433.3	484.1	30.0%	338.8	145.22	1.564	1.09	0.47	PROPANE	MINERAL PRODUCTS	LIME MANUFACT	CALCINING ROTARY KILN
					Lime Kilns, Total					**588.9**	734.4	30.0%	514.1	**220.3**	**2.54**	**1.78**	**0.76**				
031258ABR	516.7	Mittal Steel USA - Riverdale Inc	3312	0184	TUNNEL FURNACE	01		30390003	7b	123	44.1	60.0%	17.6	26.47	0.1502	0.06	0.09	NATURAL GAS	PRIMARY METAL PRODUCT	PROCESS HEATE	NATURAL GAS
					Annealing Furnace, Iron and Steel, Total					**123.0**	**44.1**	60.0%	**17.6**	**26.5**	**0.15**	**0.06**	**0.09**				
031600AIN	32962.1	Crawford Electric Generating Statio	4911	0013	Unit 7	01	Coal	10100226	8a	2342	873.9	32.1%	593.3	282.53	2.746	1.86	0.89	COAL - SUBBITUMINOU	EXTERNAL COMBUSTION B	SUBBITUMINOUS	PULVERIZED COAL DRY BOTTOM (TANGENTIAL)
031600AIN	32962.1	Crawford Electric Generating Statio	4911	0016	Unit 8	01	Coal	10100226	8a	3356	1375.0	39.6%	830.5	544.46	4.1789	2.52	1.65	COAL - SUBBITUMINOU	EXTERNAL COMBUSTION B	SUBBITUMINOUS	PULVERIZED COAL DRY BOTTOM (TANGENTIAL)
031600AMI	13414.4	Fisk Electric Generating Station	4911	0010	FISK UNIT #19	01	COAL FIRING	10100226	8a	2896	1125.6	34.8%	734.1	391.52	3.8275	2.50	1.33	COAL - SUBBITUMINOU	EXTERNAL COMBUSTION B	SUBBITUMINOUS	PULVERIZED COAL DRY BOTTOM (TANGENTIAL)
097190AAC	47103.0	Waukegan Electric Generating Stati	4911	0031	UNIT #6 BOILER	01	COAL FIRING	10100203	8a	1024	1627.3	86.6%	218.6	1408.72	5.9706	0.80	5.17	COAL - SUBBITUMINOU	EXTERNAL COMBUSTION B	BITUMINOUS CO	CYCLONE FURNACE
097190AAC	47103.0	Waukegan Electric Generating Stati	4911	0033	UNIT #8 BOILER	01	COAL FIRING	10100226	8a	3271	1595.4	33.8%	1055.8	539.62	4.6723	3.09	1.58	COAL - SUBBITUMINOU	EXTERNAL COMBUSTION B	SUBBITUMINOUS	PULVERIZED COAL DRY BOTTOM (TANGENTIAL)
097190AAC	47103.0	Waukegan Electric Generating Stati	4911	0036	UNIT #7 BOILER	01	COAL FIRING	10100226	8a	2911	1397.9	34.8%	911.6	486.21	4.2867	2.79	1.48	COAL - SUBBITUMINOU	EXTERNAL COMBUSTION B	SUBBITUMINOUS	PULVERIZED COAL DRY BOTTOM (TANGENTIAL)

197809AAO	60970 8	Midwest Generation LLC	4911	0009	Joliet 9 Unit 6 cyclone boiler	01	Coal	10100203	[illegible]	2846	5418 6	81.9%	981.2	4437 33	16 0078	3 06	13 85	COAL - SUBBITUMINO	EXTERNAL COMBUSTION B	BITUMINOUS CO	CYCLONE FURNACE
197809AAO	60970 8	Midwest Generation LLC	4911	0031	Joliet 29, Unit 7 Boilers 71 and 72	01	Coal	10100202	[illegible]	4358	1760 7	25.0%	1120 5	440 16	6.0416	4 53	1.31	COAL - SUBBITUMINO	EXTERNAL COMBUSTION B	BITUMINOUS CO	PULVERIZED COAL, DRY BOTTOM
197809AAO	60970 8	Midwest Generation LLC	4911	0033	Joliet 29: Unit 8 Boilers 81 and 82	01	Coal	10100202	[illegible]	3193	1879 2	26.2%	1386 3	492 89	5 9808	4 42	1 57	COAL - SUBBITUMINO	EXTERNAL COMBUSTION B	BITUMINOUS CO	PULVERIZED COAL, DRY BOTTOM
197810AAK	18014 4	Will County Electric Generating Sta	4911	0010	UNIT #1 BOILER CYCLONE	02	COAL FIRING	10100223	[illegible]	1728	2679 0	85 1%	397 9	2281 09	9 5894	1.42	8 17	COAL - SUBBITUMINO	EXTERNAL COMBUSTION B	SUBBITUMINOUS	CYCLONE FURNACE
197810AAK	18014 4	Will County Electric Generating Sta	4911	0012	UNIT #2 BOILER CYCLONE	02	COAL FIRED	10100223	[illegible]	1712	2531 0	83 1%	426.6	2104 41	9 1506	1 54	7 61	COAL - SUBBITUMINO	EXTERNAL COMBUSTION B	SUBBITUMINOUS	CYCLONE FURNACE
197810AAK	18014 4	Will County Electric Generating Sta	4911	0014	UNIT #3 BOILER PULV. DRY BOTTOM - TANGENTIALY F	02	COAL FIRED	10100222	[illegible]	2709	873 1	23 1%	671 6	201 48	2.7744	2.13	0.64	COAL - SUBBITUMINO	EXTERNAL COMBUSTION B	SUBBITUMINOUS	PULVERIZED COAL, DRY BOTTOM
197810AAK	18014 4	Will County Electric Generating Sta	4911	0016	UNIT #4 BOILER PULV. DRY BOTTOM - TANGENTIALY F	02	COAL FIRED	10100222	[illegible]	5016	1690 8	35 7%	1086 9	603 86	8.0984	3 92	2 18	COAL - SUBBITUMINO	EXTERNAL COMBUSTION B	SUBBITUMINOUS	PULVERIZED COAL, DRY BOTTOM
					EGU Coal-fired Boilers, Total					37902	**14827.2**	**57.3%**	**10612.9**	**14314.3**	**82.22**	**34.99**	**47.43**				
					All Sources in Chicago NAA, Total		**Total**	**Total**			**32331**	**55.6%**	**14343**	**17988**	**105.9**	**46.2**	**59.7**				

Table G-1: NOx Reductions from the Application of NOx RACT in Metro-East NAA

Mydocument/TSD/NOx RACT-Attachments.xls

Facility ID	Source PTE TPY NOx	Facility Name	SIC	Emission Unit ID	Emission Point Description	Mode ID	Mode Description	SCC #	Emission Unit category	Heat Input Capacity mmbtu/hr	2005 NOx Emissions tpy	Estimated NOx RACT Reduction, %	Estimated Controlled NOx tpy	Estimated NOx Reduction Tons	Unit Typical Ozone Season NOx tons/day	Estimated Ozone Season Controlled NOx TPD	Estimated Ozone season NOx Reduction,	Fuel	descr1	descr3	descr4
119090AAA	13872.0	ConocoPhillips Co	2911	0080	UTILITY BOILER #15 (BLR-15)	02	RFG	10200701	1a1	360	106.9	69.2%	32.9	74.02	0.2929	0.09	0.20	OTHER GAS	EXTERNAL C	PROCESS GA	PETROLEUM REFINERY GAS
119090AAA	13872.0	ConocoPhillips Co	2911	0081	UTILITY BOILER #16 (BLR-16)	02	RFG	10200701	1a1	249	149.4	69.2%	46.0	103.43	0.4093	0.13	0.28	OTHER GAS	EXTERNAL C	PROCESS GA	PETROLEUM REFINERY GAS
119090AAA	13872.0	ConocoPhillips Co	2911	0082	UTILITY BOILER #17 (BLR-17)	02	RFG	10200701	1a1	700	125.2	69.2%	38.5	86.69	0.3431	0.11	0.24	OTHER GAS	EXTERNAL C	PROCESS GA	PETROLEUM REFINERY GAS
119090AAA	13872.0	ConocoPhillips Co	2911	0083	UTILITY BOILER #18 (BLR-18)	01	NATURAL GAS	10200601	1a1	249	86.8	69.2%	26.7	60.10	0.2378	0.07	0.16	NATURAL G	EXTERNAL C	NATURAL G	>100 MBTU/HR
119090AAA	13872.0	ConocoPhillips Co	2911	0083	UTILITY BOILER #18 (BLR-18)	02	REFINERY FUEL GAS	10200701	1a1	249	30.0	69.2%	9.2	20.74	0.0821	0.03	0.06	OTHER GAS	EXTERNAL C	PROCESS GA	PETROLEUM REFINERY GAS
119813AAI	7044.1	US Steel Granite City	3312	0044	BOILER HOUSE 2 BOILER #11 - BLAST FURNACE DEPT	04	NATURAL GAS FIRIN	10200601	1a1	225	25.7	69.2%	7.9	17.78	0.0654	0.02	0.05	NATURAL G	EXTERNAL C	NATURAL G	>100 MBTU/HR
119813AAI	7044.1	US Steel Granite City	3312	0044	BOILER HOUSE 2 BOILER #11 - BLAST FURNACE DEPT	01	BLAST FURNACE GA	10200704	1a1	225	31.7	69.2%	9.8	21.96	0.0454	0.01	0.03	PROCESS GA	EXTERNAL C	PROCESS GA	BLAST FURNACE GAS
119813AAI	7044.1	US Steel Granite City	3312	0048	BOILER HOUSE 2 BOILER #12 - BLAST FURNACE DEPT	04	NATURAL GAS FIRIN	10200601	1a1	225	24.8	69.2%	7.6	17.15	0.0458	0.01	0.03	NATURAL G	EXTERNAL C	NATURAL G	>100 MBTU/HR
119813AAI	7044.1	US Steel Granite City	3312	0048	BOILER HOUSE 2 BOILER #12 - BLAST FURNACE DEPT	01	BLAST FURNACE GA	10200704	1a1	225	21.2	69.2%	6.5	14.70	0.0438	0.01	0.03	PROCESS GA	EXTERNAL C	PROCESS GA	BLAST FURNACE GAS
119813AAI	7044.1	US Steel Granite City	3312	0048	BOILER HOUSE 2 BOILER #12 - BLAST FURNACE DEPT	02	COKE OVEN GAS FIR	10200707	1a1	225	64.5	69.2%	19.9	44.67	0.138	0.04	0.10	PROCESS GA	EXTERNAL C	PROCESS GA	COKE OVEN GAS
163045ADT	168.3	Elementis Pigments Inc	2816	0061	Erie City boiler	01	Natural gas	10200601	1a1	135	41.4	69.2%	12.7	28.65	0.258	0.08	0.18	NATURAL G	EXTERNAL C	NATURAL G	>100 MBTU/HR
163121AAY	250.1	Environmental Management	4961	0001	BOILERS #1, #2 AND #3	01	NATURAL GAS	10200601	1a1	393	22.4	69.2%	6.9	15.53	0.0553	0.02	0.04	NATURAL G	EXTERNAL C	NATURAL G	>100 MBTU/HR
					Gaseous Fuel-fired Boilers >100 mmBtu/hr, Total					**3460.0**	**730.1**	69.2%	**224.6**	**505.4**	**2.02**	**0.62**	**1.40**				
119090AAA	13872.0	ConocoPhillips Co	2911	0614	BOILER NO 5	01	NATURAL GAS COM	10200602	1a2	66	15.3	15.0%	13.0	2.29	0.0419	0.04	0.01	NATURAL G	EXTERNAL C	NATURAL G	10-100 MMBTU/HR
119813AAI	7044.1	US Steel Granite City	3312	0041	BOILER HOUSE 1 BOILERS 1 TO 7	01	BLAST FURNACE GA	10200704	1a2	60	66.0	15.0%	56.1	9.89	0.1502	0.13	0.02	PROCESS GA	EXTERNAL C	PROCESS GA	BLAST FURNACE GAS
119813AAI	7044.1	US Steel Granite City	3312	0041	BOILER HOUSE 1 BOILERS 1 TO 7	04	NATURAL GAS FIRIN	10200601	1a2	420	44.6	15.0%	37.9	6.69	0.1538	0.13	0.02	NATURAL G	EXTERNAL C	NATURAL G	>100 MBTU/HR
119813AAI	7044.1	US Steel Granite City	3312	0041	BOILER HOUSE 1 BOILERS 1 TO 7	02	COKE OVEN GAS FIR	10200707	1a2	559	134.2	15.0%	114.0	20.12	0.4103	0.35	0.06	PROCESS GA	EXTERNAL C	PROCESS GA	COKE OVEN GAS
119813AAI	7044.1	US Steel Granite City	3312	0042	BOILER HOUSE 1 BOILERS 8 TO 10	04	NATURAL GAS FIRIN	10200602	1a2	60	19.1	15.0%	16.3	2.87	0.0658	0.06	0.01	NATURAL G	EXTERNAL C	NATURAL G	10-100 MMBTU/HR
119813AAI	7044.1	US Steel Granite City	3312	0042	BOILER HOUSE 1 BOILERS 8 TO 10	01	BLAST FURNACE GA	10200704	1a2	80	28.3	15.0%	24.0	4.24	0.0644	0.05	0.01	PROCESS GA	EXTERNAL C	PROCESS GA	BLAST FURNACE GAS
119813AAI	7044.1	US Steel Granite City	3312	0042	BOILER HOUSE 1 BOILERS 8 TO 10	02	COKE OVEN GAS FIR	10200707	1a2	60	57.5	15.0%	48.9	8.63	0.1756	0.15	0.03	PROCESS GA	EXTERNAL C	PROCESS GA	COKE OVEN GAS
					Gaseous Fuel-fired Boilers <=100 mmBtu/hr, Total					1305	**364.9**	15.0%	**310.2**	**54.7**	**1.06**	**0.90**	**0.16**				
119090AAA	13872.0	ConocoPhillips Co	2911	0004	CAT REFORMER #1 FEED PREHEATER (HTR-CR1-H1)	02	RFG	30600106	2a1	165	130.8	28.6%	93.5	37.38	0.3584	0.26	0.10	OTHER GAS	PETROLEUM	PROCESS HE	PROCESS GAS-FIRED
119090AAA	13872.0	ConocoPhillips Co	2911	0005	CAT REFORMER #1 FIRST INTERREACTOR HEATER (HTR-CR	02	RFG	30600104	2a1	162	164.3	28.6%	117.4	46.95	0.4502	0.32	0.13	OTHER GAS	PETROLEUM	PROCESS HE	GAS FIRED
119090AAA	13872.0	ConocoPhillips Co	2911	0014	HYDROCRACKING UNIT FRACTIONATOR REBOILER (HTR-HCU	02	RFG	30600106	2a1	235	152.0	28.6%	108.6	43.43	0.4164	0.30	0.12	OTHER GAS	PETROLEUM	PROCESS HE	PROCESS GAS-FIRED
119090AAA	13872.0	ConocoPhillips Co	2911	0018	BENZENE EXTRACTION UNIT #2 (HTR-BEU-HM2)	02	RFG	30600106	2a1	110	59.5	28.6%	42.5	16.99	0.163	0.12	0.05	OTHER GAS	PETROLEUM	PROCESS HE	PROCESS GAS-FIRED
119090AAA	13872.0	ConocoPhillips Co	2911	0024	DISTILLING UNIT HTR-DU1-F301	02	REFINERY GAS (RFG	30600106	2a1	120	138.8	28.6%	99.1	39.66	0.3803	0.27	0.11	OTHER GAS	PETROLEUM	PROCESS HE	PROCESS GAS-FIRED
119090AAA	13872.0	ConocoPhillips Co	2911	0025	DISTILLING UNIT HTR-DU1-F302	01	RFG	30600106	2a1	200	226.9	28.6%	162.1	64.84	0.6217	0.44	0.18	OTHER GAS	PETROLEUM	PROCESS HE	PROCESS GAS-FIRED
119090AAA	13872.0	ConocoPhillips Co	2911	0029	DISTILLING UNIT WEST CRUDE HEATER (HTR-DU2-F202)	02	REFINERY GAS (RFG	30600104	2a1	230	221.7	28.6%	158.3	63.33	0.6073	0.43	0.17	OTHER GAS	PETROLEUM	PROCESS HE	GAS FIRED
119090AAA	13872.0	ConocoPhillips Co	2911	0030	DISTILLING UNIT EAST CRUDE HEATER (HTR-DU2-F203)	01	RFG	30600106	2a1	230	226.6	28.6%	161.8	64.74	0.6208	0.44	0.18	OTHER GAS	PETROLEUM	PROCESS HE	PROCESS GAS-FIRED
119090AAA	13872.0	ConocoPhillips Co	2911	0073	ALKYLATION UNIT HTR-ALKY-HM2	02	RFG	30600106	2a1	110	76.6	28.6%	54.7	21.89	0.2098	0.15	0.06	OTHER GAS	PETROLEUM	PROCESS HE	PROCESS GAS-FIRED
119090AAA	13872.0	ConocoPhillips Co	2911	0084	CAT REFORMER #2 CHARGE REHEATER (HTR-CR2-N)	01	RFG	30600106	2a1	137.5	65.4	28.6%	46.7	18.68	0.1792	0.13	0.05	OTHER GAS	PETROLEUM	PROCESS HE	PROCESS GAS-FIRED
119090AAA	13872.0	ConocoPhillips Co	2911	0086	HEATER CR2-S (RFG FIRING)	01	FUEL COMBUSTION	30600104	2a1	137.5	65.4	28.6%	46.7	18.68	0.1792	0.13	0.05	OTHER GAS	PETROLEUM	PROCESS HE	GAS FIRED
119090AAA	13872.0	ConocoPhillips Co	2911	0091	CAT REFORMER #3 CHARGE HEATER (HTR-CR3-H4)	01	RFG	30600106	2a1	144.7	165.1	28.6%	118.0	47.18	0.4524	0.32	0.13	OTHER GAS	PETROLEUM	PROCESS HE	PROCESS GAS-FIRED
119090AAA	13872.0	ConocoPhillips Co	2911	0092	CAT REFORMER #3 FIRST INTERREACTOR HEATER (HTR-CR	02	RFG	30600106	2a1	141	136.8	28.6%	97.7	39.08	0.3748	0.27	0.11	OTHER GAS	PETROLEUM	PROCESS HE	PROCESS GAS-FIRED
119090AAA	13872.0	ConocoPhillips Co	2911	0094	KEROSENE HYDROTREATER KHT HEATER (HTR-KHT)	01	RFG	30600106	2a1	109	106.2	28.6%	75.8	30.33	0.2908	0.21	0.08	OTHER GAS	PETROLEUM	PROCESS HE	PROCESS GAS-FIRED
119090AAA	13872.0	ConocoPhillips Co	2911	0617	DELAYED COKER UNIT HEATER H-20	02	REFINERY FUEL GAS	30600106	2a1	231	98.1	28.6%	70.1	28.03	0.2688	0.19	0.08	OTHER GAS	PETROLEUM	PROCESS HE	PROCESS GAS-FIRED
119090AAA	13872.0	ConocoPhillips Co	2911	0623	NO.2 CRUDE UNIT HEATER H-24	01	NATURAL GAS COM	30600104	2a1	314	150.2	28.6%	107.3	42.92	1.0018	0.72	0.29	NATURAL G	PETROLEUM	PROCESS HE	GAS FIRED
					Process Htrs Gas fired >100 mmBtu/hr, Total					**2776.7**	**2184.4**	28.6%	**1560.3**	**624.1**	**6.58**	**4.70**	**1.88**				
119090AAA	13872.0	ConocoPhillips Co	2911	0006	CAT REFORMER #1 SECOND INTERREACTOR HEATER (HTR-C	02	RFG	30600104	2a2	78	27.8	15.0%	23.6	4.17	0.0761	0.06	0.01	OTHER GAS	PETROLEUM	PROCESS HE	GAS FIRED
119090AAA	13872.0	ConocoPhillips Co	2911	0007	CAT REFORMER #1 STABILIZER REBOILER (HTR-CR1-H4)	02	RFG	30600106	2a2	100	16.7	15.0%	14.2	2.51	0.0458	0.04	0.01	OTHER GAS	PETROLEUM	PROCESS HE	PROCESS GAS-FIRED
119090AAA	13872.0	ConocoPhillips Co	2911	0009	CAT REFORMER #1 THIRD INTERREACTOR HEATER (HTR-CR	02	RFG	30600106	2a2	100	86.7	15.0%	73.7	13.00	0.2375	0.20	0.04	OTHER GAS	PETROLEUM	PROCESS HE	PROCESS GAS-FIRED
119090AAA	13872.0	ConocoPhillips Co	2911	0017	BENZENE EXTRACTION UNIT #1 (HTR-BEU-HM1)	02	RFG	30600106	2a2	100	81.7	15.0%	69.5	12.26	0.2239	0.19	0.03	OTHER GAS	PETROLEUM	PROCESS HE	PROCESS GAS-FIRED
119090AAA	13872.0	ConocoPhillips Co	2911	0031	VACUUM FLASHER UNITS #1-3 (VF-1, -2, -3)	01		30600104	2a2	273	140.2	15.0%	119.1	21.02	0.384	0.33	0.06	OTHER GAS	PETROLEUM	PROCESS HE	GAS FIRED
119090AAA	13872.0	ConocoPhillips Co	2911	0033	RECTIFIED ABSORPTION UNIT REBOILER HEATER (HTR-RA	01	RFG	30600106	2a2	69	23.0	15.0%	19.5	3.44	0.0629	0.05	0.01	OTHER GAS	PETROLEUM	PROCESS HE	PROCESS GAS-FIRED
119090AAA	13872.0	ConocoPhillips Co	2911	0036	CRACKED ABSORPTION UNIT (HTR-CAU-ROSTILL)	02	RFG AND RFP	30600106	2a2	95	30.0	15.0%	25.5	4.50	0.0822	0.07	0.01	OTHER GAS	PETROLEUM	PROCESS HE	PROCESS GAS-FIRED
119090AAA	13872.0	ConocoPhillips Co	2911	0042	CO HEATER (HTRR-CCU1-CO)	01	RFG	30600104	2a2	17	91.9	15.0%	78.1	13.78	0.2518	0.21	0.04	PROCESS GA	PETROLEUM	PROCESS HE	GAS FIRED
119090AAA	13872.0	ConocoPhillips Co	2911	0056	CO HEATER (HTRR-CCU2-CO)	01	RFG	30600104	2a2	80	82.1	15.0%	69.8	12.31	0.2249	0.19	0.03	OTHER GAS	PETROLEUM	PROCESS HE	GAS FIRED
119090AAA	13872.0	ConocoPhillips Co	2911	0085	HYDRODESULFURIZATION UNIT #1 CHARGE HEATER (HTR-H	01	RFG	30600106	2a2	67.3	19.6	15.0%	16.6	2.94	0.0536	0.05	0.01	OTHER GAS	PETROLEUM	PROCESS HE	PROCESS GAS-FIRED
119090AAA	13872.0	ConocoPhillips Co	2911	0088	HYDRODESULFURIZATION UNIT #2 CHARGE HEATER (HTR-H	01	RFG	30600106	2a2	81	26.2	15.0%	22.3	3.94	0.0719	0.06	0.01	OTHER GAS	PETROLEUM	PROCESS HE	PROCESS GAS-FIRED
119090AAA	13872.0	ConocoPhillips Co	2911	0093	CAT REFORMER #3 SECOND INTERREACTOR HEATER (HTR-C	02	RFG	30600106	2a2	74	27.1	15.0%	23.0	4.06	0.0742	0.06	0.01	OTHER GAS	PETROLEUM	PROCESS HE	PROCESS GAS-FIRED
119090AAA	13872.0	ConocoPhillips Co	2911	0154	VACUUM FLASHER #2 EAST HEATER (HTR-VF2-F205)	01	RFG	30600106	2a2	61	15.9	15.0%	13.5	2.39	0.0436	0.04	0.01	OTHER GAS	PETROLEUM	PROCESS HE	PROCESS GAS-FIRED
119090AAA	13872.0	ConocoPhillips Co	2911	0155	VACUUM FLASHER #1 NORTH HEATER (HTR-VF-1-NORTH)	01		30600105	2a2	100	45.5	15.0%	38.7	6.83	0.1247	0.11	0.02	NATURAL G	PETROLEUM	PROCESS HE	NATURAL GAS-FIRED
119090AAA	13872.0	ConocoPhillips Co	2911	0156	VACUUM FLASHER #1 SOUTH HEATER (HTR-VF-1-SOUTH)	01		30600105	2a2	100	50.9	15.0%	43.3	7.64	0.1394	0.12	0.02	NATURAL G	PETROLEUM	PROCESS HE	NATURAL GAS-FIRED
					Process Htrs Gas fired <100 mmBtu/hr, Total					**1996.3**	**765.2**	15.0%	**650.4**	**114.8**	**2.10**	**1.78**	**0.31**				
119010AAE	1916.7	Alton Steel Inc	3312	0033	14 INCH BILLET REHEAT FURNACE	01	GAS FIRED	30300933	7a	255	47.6	77.0%	11.0	36.68	0.3174	0.07	0.24	NATURAL G	PRIMARY M	STEEL PROD	REHEAT FURNACES
119813AAI	7044.1	US Steel Granite City	3312	0015	SLAB FURNACE #1	02	COKE OVEN GAS FIR	39000689	7a	321.8	84.9	77.0%	19.5	65.40	0.4144	0.10	0.32	PROCESS GA	IN-PROCESS	NATURAL G	GENERAL
119813AAI	7044.1	US Steel Granite City	3312	0015	SLAB FURNACE #1	01	NATURAL GAS FIRIN	39000689	7a	321.8	266.2	77.0%	61.2	205.00	0.7066	0.16	0.55	NATURAL G	IN-PROCESS	NATURAL G	GENERAL
119813AAI	7044.1	US Steel Granite City	3312	0018	SLAB FURNACE #4	01	NATURAL GAS FIRIN	39000689	7a	495	113.8	77.0%	26.2	87.65	0.9587	0.22	0.74	NATURAL G	IN-PROCESS	NATURAL G	GENERAL
119813AAI	7044.1	US Steel Granite City	3312	0122	SLAB FURNACE #2	02	COKE OVEN GAS FIR	39000689	7a	322	82.2	77.0%	18.9	63.32	0.3838	0.09	0.30	PROCESS GA	IN-PROCESS	NATURAL G	GENERAL
119813AAI	7044.1	US Steel Granite City	3312	0122	SLAB FURNACE #2	01	NATURAL GAS FIRIN	39000689	7a	322	149.2	77.0%	34.3	114.89	0.6908	0.16	0.53	NATURAL G	IN-PROCESS	NATURAL G	GENERAL
119813AAI	7044.1	US Steel Granite City	3312	0123	SLAB FURNACE #3	02	COKE OVEN GAS FIR	39000689	7a	322	101.6	77.0%	23.4	78.19	0.4321	0.10	0.33	PROCESS GA	IN-PROCESS	NATURAL G	GENERAL
119813AAI	7044.1	US Steel Granite City	3312	0123	SLAB FURNACE #3	01	NATURAL GAS FIRIN	39000689	7a	322	162.8	77.0%	37.5	125.39	0.7062	0.16	0.54	NATURAL G	IN-PROCESS	NATURAL G	GENERAL
					Reheat Furnaces, Iron and Steel, Total					**2681.6**	**1008.5**	77.0%	**231.9**	**776.5**	**4.62**	**1.06**	**3.56**				
119020AAE	24289.8	Dynegy Midwest Generation	4911	0001	BOILER 5 PULV DRY TANGENTIAL	01	COAL FIRING	10100202	8a	3920	1910.9	43.4%	1081.6	829.26	5.3283	3.02	2.31	COAL - SUBB	EXTERNAL C	BITUMINOU	PULVERIZED COAL DRY BOTTOM
119020AAE	24289.8	Dynegy Midwest Generation	4911	0003	BLR 4 PULV DRY BTM TANGENTIAL	01	COAL FIRING	10100202	8a	1030	456.6	32.8%	306.7	149.93	1.5082	1.01	0.50	COAL - SUBB	EXTERNAL C	BITUMINOU	PULVERIZED COAL DRY BOTTOM
157851AAA	4875.6	Dynegy Midwest Generation	4911	0001	BOILER #1	01	COAL FIRING	10100202	8a	5890	1108.9	-20.0%	1330.3	-221.39	3.627	4.35	-0.73	COAL - SUBBITUMINOUS			
157851AAA	4875.6	Dynegy Midwest Generation	4911	0002	BOILER #2	01	COAL FIRING	10100202	8a	5900	1495.3	-22.2%	1827.6	-332.29	3.547	4.34	-0.79	COAL - SUBBITUMINOUS			
157851AAA	4875.6	Dynegy Midwest Generation	4911	0013	BOILER #3	01	COAL FIRING	10100202	8a	5100	2271.6	7.8%	2095.0	176.68	6.624	6.11	0.52	COAL - SUBBITUMINOUS			
					EGU Coal-fired Boilers, Total					22540	**7241**	**8.3%**	**6639**	**602**	**20.6**	**18.8**	**1.8**				
					All Sources in Metro-East NAA, Total						**12294**	21.8%	**9617**	**2678**	**37**	**28**	**9**				

Table H-1: NOx Reductions from the Application of NOx RACT in Chicago and Metro-East NAA

Mydocument/TSD/NOx RACT-Attachments.xls

Sr No	Facility ID	Source PTE TPY NOx	Facility Name	SIC	Emission Unit ID	Emission Point Description	Mode ID	SCC #	Emission Unit category	Heat Input Capacity mmbtu/hr	2005 NOx Emissions tpy	Estimated NOx RACT Reduction, %	Estimated Controlled NOx tpy	Estimated Nox Reduction Tons	Unit Typical Ozone Season NOx tons/day	Estimated Ozone Season Controlled NOx, TPD	Estimated Ozone season NOx Reduction, TPD	Fuel	descr1	descr3	descr4
1	031003ADA	516.7	Alsip Paper Condominium Assn	4911	0004	BOILERS #1 AND #2	01	10200601	1a1	310	173.1	69.2%	53.3	119.85	0.2184	0.07	0.151	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
2	031012AAO	139.6	Nalco Co	2899	0049	BOILER #1	01	10200601	1a1	114.6	17.9	69.2%	5.5	12.41	0.0656	0.02	0.05	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
3	031012AAO	139.6	Nalco Co	2899	0061	BOILER #2	01	10200601	1a1	124	42.3	69.2%	13.0	29.26	0.2875	0.09	0.20	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
4	031012ABI	4542.4	Corn Products International Inc	2046	0046	UTILITIES - BOILER #5 (A-23-93)	01	10200601	1a1	312.5	39.2	69.2%	12.0	27.11	0.064	0.02	0.04	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
5	031012ABI	4542.4	Corn Products International Inc	2046	0160	UTILITIES - BOILER #6 (A23-144)	01	10200601	1a1	600	16.8	69.2%	5.2	11.66	0.0384	0.01	0.03	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
6	031012ABI	4542.4	Corn Products International Inc	2046	0233	UTILITIES - BOILER #7	01	10200601	1a1	240	30.5	69.2%	9.4	21.09	0.087	0.03	0.06	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
7	031012ABI	4542.4	Corn Products International Inc	2046	0041	UTILITIES - BOILER #1 (A-23-92)	01	10200202	1e2	332.5	760.7	73.9%	198.4	562.26	3.1978	0.83	2.36	COAL - BITUMINOUS	EXTERNAL COMBUSTION B	BITUMINOUS COA	PULVERIZED COAL: DRY BOTTOM
8	031012ABI	4542.4	Corn Products International Inc	2046	0042	UTILITIES - BOILER #2 (A-23-92)	01	10200202	1e2	332.5	796.9	73.9%	207.9	588.98	3.2401	0.85	2.39	COAL - BITUMINOUS	EXTERNAL COMBUSTION B	BITUMINOUS COA	PULVERIZED COAL: DRY BOTTOM
9	031012ABI	4542.4	Corn Products International Inc	2046	0045	UTILITIES - BOILER #3 (A-23-93)	01	10200202	1e2	332.5	772.6	73.9%	201.6	571.08	2.4953	0.65	1.84	COAL - BITUMINOUS	EXTERNAL COMBUSTION B	BITUMINOUS COA	PULVERIZED COAL: DRY BOTTOM
10	031045AAJ	316.1	Kimble Glass Inc		0006	GLASS MELTING FURNACE B	01	30501402	3	25	50.8	50.0%	25.4	25.38	0.14	0.07	0.07				
11	031069AAI	1313.0	Saint-Gobain Containers Inc		0013	3 GLASS MELTING FURNACES (1, 2 AND 3)	01	30501402	3	120	681.2	50.0%	340.6	340.58	1.87564	0.94	0.94	NATURAL GAS			
12	031081ABQ	286.5	Northwestern University	8221	0001	3 BC Boilers (#1, 2 and 3 - Central Utility Plant)	01	10300601	1a1	556	156.7	69.2%	48.2	108.46	0.4436	0.14	0.31	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MMBTU/HR
13	031258ABR	516.7	Mittal Steel USA - Riverdale Inc	3312	0184	TUNNEL FURNACE	01	30390003	7b	123	44.1	60.0%	17.6	26.47	0.1502	0.06	0.09	NATURAL GAS	PRIMARY METAL PRODUCT	PROCESS HEATE	NATURAL GAS
14	031600ADY	1338.7	Carmeuse Lime Inc	3274	0024	ROTARY KILN 4	01	30501605	5a	155.6	250.4	30.0%	175.2	75.11	0.9888	0.69	0.30	PROPANE	MINERAL PRODUCTS	LIME MANUFACT	CALCIMATIC KILN
15	031600ADY	1338.7	Carmeuse Lime Inc	3274	0028	ROTARY KILN 5	01	30501604	5a	433.3	484.1	30.0%	338.8	145.22	1.554	1.09	0.47	PROPANE	MINERAL PRODUCTS	LIME MANUFACT	CALCINING: ROTARY KILN
16	031600AIN	32962.1	Crawford Electric Generating Static	4911	0013	Unit 7	01	10100226	4a	2342	873.9	32.3%	591.3	282.53	2.746	1.86	0.89	COAL - SUBBITUMINOU	EXTERNAL COMBUSTION B	SUBBITUMINOUS	PULVERIZED COAL: DRY BOTTOM (TANGENTIAL)
17	031600AIN	32962.1	Crawford Electric Generating Static	4911	0016	Unit 8	01	10100226	8a	3556	1375.0	39.6%	830.5	544.46	4.1789	2.52	1.65	COAL - SUBBITUMINOU	EXTERNAL COMBUSTION B	SUBBITUMINOUS	PULVERIZED COAL: DRY BOTTOM (TANGENTIAL)
18	031600AMI	15414.4	Fisk Electric Generating Station	4911	0010	FISK UNIT #19	01	10100226	8a	2896	1125.6	34.8%	734.1	391.52	3.8275	2.50	1.33	COAL - SUBBITUMINOU	EXTERNAL COMBUSTION B	SUBBITUMINOUS	PULVERIZED COAL: DRY BOTTOM (TANGENTIAL)
19	031600CAO	221.5	Kraft Foods Global Inc	2052	0107	BOILER #5	01	10200602	1a2	61.3	20.7	15.0%	17.6	3.11	0.012	0.01	0.00	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	10-100 MMBTU/HR
20	031600DDJ	175.6	National Railroad Passenger Corp	4011	0001	BOILER #1	01	10200602	1a2	77.4	16.0	15.0%	13.6	2.40	0	0.00	0.00	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	10-100 MMBTU/HR
21	031600FLT	204.3	University of Chicago	8221	0001	BOILERS 1-4	01	10200601	1a1	782	63.5	69.2%	19.5	43.94	0.1142	0.04	0.08	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
22	031600FMX	114.3	Northwestern Memorial Hospital	8062	0002	5 Boilers	01	10300602	1a2	136	31.8	15.0%	27.0	4.77	0.0874	0.07	0.01	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	10-100 MMBTU/HR
23	031600FQF	202.5	Chicago - Dept of Aviation	4581	0003	8 HIGH TEMPERATURE WATER GENERATORS (HTWO-4	01	10200602	1a2	758.6	26.0	15.0%	22.1	3.89	0.3708	0.32	0.06	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	10-100 MMBTU/HR
24	031817AAB	108.9	Loyola University Medical Center	8221	0017	BOILERS 2, 3 AND 4	01	10300602	1a2	154.9	20.6	15.0%	17.5	3.09	0.0461	0.04	0.01	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	10-100 MMBTU/HR
25	031817AAL	292.3	VA Edward Hines Jr Hospital	8062	0004	BOILERS 1-4	01	10300602	1a3	200	17.8	69.2%	5.5	12.35	0.0231	0.01	0.02	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	10-100 MMBTU/HR
26	043802AAA	727.9	Argonne National Laboratory	8733	0001	Boiler #1	01	10300601	1a1	106	25.2	69.2%	7.8	17.47	0.082	0.03	0.06	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MMBTU/HR
27	043802AAA	727.9	Argonne National Laboratory	8733	0003	Boiler #3	01	10300601	1a1	106	19.4	69.2%	6.0	13.42	0	0.00	0.00	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MMBTU/HR
28	043802AAA	727.9	Argonne National Laboratory	8733	0004	Boiler #4	01	10300601	1a1	106	19.0	69.2%	5.8	13.15	0	0.00	0.00	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MMBTU/HR
29	043802AAA	727.9	Argonne National Laboratory	8733	0005	Boiler #5	04	10300205	1e3	212	21.6	63.8%	7.8	13.8	0	0.00	0.00	COAL - SUBBITUMINOU	EXTERNAL COMBUSTION B	BITUMINOUS COA	PULVERIZED COAL: WET BOTTOM
30	063800AAC	628.1	Equistar Chemicals LP	2869	0025	ETHYLENE PLANT - STEAM SUPERHEATER	01	10200799	1a1	141	47.2	69.2%	14.5	32.69	0.1294	0.04	0.09	OTHER GASEOUS FUEL	EXTERNAL COMBUSTION B	PROCESS GAS	> 100 MBTU/HR
31	063800AAC	628.1	Equistar Chemicals LP	2869	0026	ETHYLENE PLANT - 14 CRACKING FURNACES (101-114)	01	30600104	2a1	1277	357.3	28.6%	255.2	102.07	0.9788	0.70	0.28	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
32	063800AAE	491.0	Akzo Nobel Surface Chemistry LLC	2869	0033	STEAM BOILER J-090 (NEBRASKA)	03	10201201	1e4	40.2	37.1	15.0%	31.6	5.57	0.2271	0.19	0.03	OTHER	EXTERNAL COMBUSTION B	SOLID WASTE	SPECIFY WASTE MATERIAL IN COMMENTS
33	063800AAE	491.0	Akzo Nobel Surface Chemistry LLC	2869	0017	DOWTHERM BOILER	02	10201201	2e3	17	26.5	15.0%	22.5	3.97	0.103	0.09	0.02	OTHER	EXTERNAL COMBUSTION B	SOLID WASTE	SPECIFY WASTE MATERIAL IN COMMENTS
34	063800AAM	241.8	Aux Sable Liquid Products	1321	0019	Heaters 1H101, 2H101, H501, H601, H602, 501A, 501B	01	39000699	2a1	159.3	156.1	28.6%	111.5	44.59	0.4350	0.31	0.12	NATURAL GAS	IN-PROCESS FUEL USE	NATURAL GAS	GENERAL
35	089800AAH	711.8	Dial Corp	2841	0075	BOILERS #1 AND #2	01	10200601	1a1	210	124.1	69.2%	38.2	85.89	0.3475	0.11	0.24	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
36	097125AAA	582.3	Abbott Laboratories	2834	0858	BOILER #10 NC (CED)	01	10200601	1a1	220	24.7	69.2%	7.6	17.10	0.0781	0.02	0.05	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
37	097125AAA	582.3	Abbott Laboratories	2834	0070	BOILER #5NC (TT-16) (CED)	01	10100204	1e4	85	85.5	15.0%	72.7	12.83	0.2898	0.25	0.04	COAL - BITUMINOUS	EXTERNAL COMBUSTION B	BITUMINOUS COA	SPREADER STOKER
38	097125AAA	582.3	Abbott Laboratories	2834	0542	BOILER #6 NC (TT-20) (CED)	01	10100204	1e4	85	77.1	15.0%	65.5	11.56	0.2743	0.23	0.04	COAL - BITUMINOUS	EXTERNAL COMBUSTION B	BITUMINOUS COA	SPREADER STOKER
39	097190AAC	47103.0	Waukegan Electric Generating Stat	4911	0031	UNIT #6 BOILER	01	10100203	8a	1024	1627.3	86.6%	218.6	1408.72	5.9705	0.80	5.17	COAL - SUBBITUMINOU	EXTERNAL COMBUSTION B	BITUMINOUS COA	CYCLONE FURNACE
40	097190AAC	47103.0	Waukegan Electric Generating Stati	4911	0033	UNIT #8 BOILER	01	10100226	8a	3271	1595.4	33.8%	1055.8	539.62	4.6723	3.09	1.58	COAL - SUBBITUMINOU	EXTERNAL COMBUSTION B	SUBBITUMINOUS	PULVERIZED COAL: DRY BOTTOM (TANGENTIAL)
41	097190AAC	47103.0	Waukegan Electric Generating Stati	4911	0036	UNIT #7 BOILER	01	10100226	8a	2911	1397.9	34.8%	911.6	486.21	4.2867	2.78	1.48	COAL - SUBBITUMINOU	EXTERNAL COMBUSTION B	SUBBITUMINOUS	PULVERIZED COAL: DRY BOTTOM (TANGENTIAL)
42	097809AAD	1629.2	Abbott Laboratories	2834	0006	Boiler 4AP	01	10200204	1e4	83	147.8	15.0%	125.6	22.17	0.4482	0.38	0.07	COAL - BITUMINOUS	EXTERNAL COMBUSTION B	BITUMINOUS COA	SPREADER STOKER
43	097809AAD	1629.2	Abbott Laboratories	2834	0103	Boiler #5AP	01	10200204	1e4	83	129.2	15.0%	109.8	19.38	0.3738	0.32	0.06	COAL - BITUMINOUS	EXTERNAL COMBUSTION B	BITUMINOUS COA	SPREADER STOKER
44	097811AAC	826.8	Naval Training Center	9711	0011	BUILDING 11: BOILERS #5 AND #6	01	10200601	1a1	680	94.0	69.2%	28.9	65.06	0.0341	0.01	0.02	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
45	119010AAE	1916.7	Alton Steel Inc	3312	0033	14 INCH BILLET REHEAT FURNACE	01	30300933	7a	255	47.6	77.0%	11.0	36.68	0.3174	0.07	0.24	NATURAL GAS	PRIMARY METAL PRODUCT	STEEL PRODUCT	REHEAT FURNACES
46	119020AAE	24289.8	Dynegy Midwest Generation Inc	4911	0001	BOILER 5 PULV DRY TANGENTIAL	01	10100202	8a	3920	1910.9	41.4%	1081.6	829.26	5.3293	3.02	2.31	COAL - SUBBITUMINOU	EXTERNAL COMBUSTION B	BITUMINOUS CO	PULVERIZED COAL: DRY BOTTOM
47	119020AAE	24289.8	Dynegy Midwest Generation Inc	4911	0003	BLR 4 PULV DRY BTM TANGENTIAL	01	10100202	8a	1030	456.6	32.8%	306.7	149.93	1.5082	1.01	0.50	COAL - SUBBITUMINOU	EXTERNAL COMBUSTION B	BITUMINOUS CO	PULVERIZED COAL: DRY BOTTOM
48	119090AAA	13872.0	ConocoPhillips Co	2911	0080	UTILITY BOILER #15 (BLR-15)	02	10200701	1a1	360	106.9	69.2%	32.9	74.02	0.2829	0.09	0.20	OTHER GASEOUS FUEL	EXTERNAL COMBUSTION B	PROCESS GAS	PETROLEUM REFINERY GAS
49	119090AAA	13872.0	ConocoPhillips Co	2911	0081	UTILITY BOILER #16 (BLR-16)	02	10200701	1a1	249	149.4	69.2%	46.0	103.43	0.4083	0.13	0.28	OTHER GASEOUS FUEL	EXTERNAL COMBUSTION B	PROCESS GAS	PETROLEUM REFINERY GAS
50	119090AAA	13872.0	ConocoPhillips Co	2911	0082	UTILITY BOILER #17 (BLR-17)	02	10200701	1a1	700	125.2	69.2%	38.5	86.69	0.3431	0.11	0.24	OTHER GASEOUS FUEL	EXTERNAL COMBUSTION B	PROCESS GAS	PETROLEUM REFINERY GAS
51	119090AAA	13872.0	ConocoPhillips Co	2911	0083	UTILITY BOILER #18 (BLR-18)	01	10200601	1a1	249	86.8	69.2%	26.7	60.10	0.2378	0.07	0.16	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
52	119090AAA	13872.0	ConocoPhillips Co	2911	0083	UTILITY BOILER #18 (BLR-18)	02	10200701	1a1	249	30.0	69.2%	9.2	20.74	0.0821	0.03	0.06	OTHER GASEOUS FUEL	EXTERNAL COMBUSTION B	PROCESS GAS	PETROLEUM REFINERY GAS
53	119090AAA	13872.0	ConocoPhillips Co	2911	0614	BOILER NO. 5	01	10200602	1a2	66	15.3	15.0%	13.0	2.29	0.0419	0.04	0.01	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	10-100 MMBTU/HR
54	119090AAA	13872.0	ConocoPhillips Co	2911	0004	CAT REFORMER #1: FEED PREHEATER (HTR-CR1-H1)	02	30600106	2a1	165	130.8	28.6%	93.5	37.38	0.3584	0.26	0.10	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
55	119090AAA	13872.0	ConocoPhillips Co	2911	0005	CAT REFORMER #1: FIRST INTERREACTOR HEATER (H	02	30600104	2a1	162	164.3	28.6%	117.4	46.95	0.4502	0.32	0.13	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
56	119090AAA	13872.0	ConocoPhillips Co	2911	0014	HYDROCRACKING UNIT: FRACTIONATOR REBOILER (H	02	30600106	2a1	235	152.0	28.6%	108.6	43.43	0.4164	0.30	0.12	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
57	119090AAA	13872.0	ConocoPhillips Co	2911	0018	BENZENE EXTRACTION UNIT #2 (HTR-BEU-HM2)	02	30600106	2a1	110	59.5	28.6%	42.5	16.99	0.163	0.12	0.05	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
58	119090AAA	13872.0	ConocoPhillips Co	2911	0024	DISTILLING UNIT: HTR-DU1-F301	02	30600106	2a1	120	138.8	28.6%	99.1	39.66	0.3803	0.27	0.11	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
59	119090AAA	13872.0	ConocoPhillips Co	2911	0025	DISTILLING UNIT: HTR-DU1-F302	01	30600106	2a1	200	226.9	28.6%	162.1	64.84	0.6217	0.44	0.18	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
60	119090AAA	13872.0	ConocoPhillips Co	2911	0029	DISTILLING UNIT: WEST CRUDE HEATER (HTR-DU2-F201	02	30600104	2a1	290	221.7	28.6%	158.3	63.33	0.6073	0.43	0.17	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
61	119090AAA	13872.0	ConocoPhillips Co	2911	0030	DISTILLING UNIT: EAST CRUDE HEATER (HTR-DU2-F202	01	30600106	2a1	230	226.6	28.6%	161.8	64.74	0.6208	0.44	0.18	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
62	119090AAA	13872.0	ConocoPhillips Co	2911	0073	ALKYLATION UNIT: HTR-ALKY-HM2	02	30600106	2a1	110	76.6	28.6%	54.7	21.89	0.2099	0.15	0.06	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
63	119090AAA	13872.0	ConocoPhillips Co	2911	0084	CAT REFORMER #2: CHARGE REHEATER (HTR-CR2-N)	01	30600106	2a1	137.5	65.4	28.6%	46.7	18.68	0.1792	0.13	0.05	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
64	119090AAA	13872.0	ConocoPhillips Co	2911	0086	HEATER CR2-S (RFG FIRING)	01	30600104	2a1	137.5	65.4	28.6%	46.7	18.68	0.1792	0.13	0.05	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
65	119090AAA	13872.0	ConocoPhillips Co	2911	0091	CAT REFORMER #3: CHARGE HEATER (HTR-CR3-H6)	01	30600106	2a1	144.7	165.1	28.6%	118.0	47.18	0.4524	0.32	0.13	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
66	119090AAA	13872.0	ConocoPhillips Co	2911	0092	CAT REFORMER #3: FIRST INTERREACTOR HEATER (H	02	30600106	2a1	141	136.8	28.6%	97.7	39.08	0.3748	0.27	0.11	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
67	119090AAA	13872.0	ConocoPhillips Co	2911	0094	KEROSENE HYDROTREATER: KHT HEATER (HTR-KHT)	01	30600106	2a1	109	106.2	28.6%	75.8	30.33	0.2909	0.21	0.08	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
68	119090AAA	13872.0	ConocoPhillips Co	2911	0617	DELAYED COKER UNIT HEATER H-20	02	30600106	2a1	231	98.1	28.6%	70.1	28.03	0.2688	0.19	0.08	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
69	119090AAA	13872.0	ConocoPhillips Co	2911	0625	NO.2 CRUDE UNIT HEATER H-24	01	30600104	2a1	314	150.2	28.6%	107.3	42.92	1.0016	0.72	0.29	NATURAL GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
70	119090AAA	13872.0	ConocoPhillips Co	2911	0006	CAT REFORMER #1: SECOND INTERREACTOR HEATER	02	30600104	2a2	78	27.8	15.0%	23.6	4.17	0.0761	0.06	0.01	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
71	119090AAA	13872.0	ConocoPhillips Co	2911	0007	CAT REFORMER #1: STABILIZER REBOILER (HTR-CR1-H	02	30600106	2a2	100	16.7	15.0%	14.2	2.51	0.0458	0.04	0.01	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
72	119090AAA	13872.0	ConocoPhillips Co	2911	0009	CAT REFORMER #1: THIRD INTERREACTOR HEATER (H	02	30600106	2a2	100	86.7	15.0%	73.7	13.00	0.2375	0.20	0.04	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
73	119090AAA	13872.0	ConocoPhillips Co	2911	0017	BENZENE EXTRACTION UNIT #1 (HTR-BEU-HM1)	02	30600106	2a2	100	81.7	15.0%	69.5	12.26	0.2239	0.19	0.03	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
74	119090AAA	13872.0	ConocoPhillips Co	2911	0031	VACUUM FLASHER UNITS #1-3 (VF-1, -2, -3)	01	30600104	2a2	273	140.2	15.0%	119.1	21.02	0.384	0.33	0.06	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
75	119090AAA	13872.0	ConocoPhillips Co	2911	0033	RECTIFIED ABSORPTION UNIT: REBOILER HEATER (HT	01	30600106	2a2	69	23.0	15.0%	19.5	3.44	0.0629	0.05	0.01	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
76	119090AAA	13872.0	ConocoPhillips Co	2911	0036	CRACKED ABSORPTION UNIT (HTR-CAU-ROSTILL)	02	30600106	2a2	95	30.0	15.0%	25.5	4.50	0.0822	0.07	0.01	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
77	119090AAA	13872.0	ConocoPhillips Co	2911	0042	CO HEATER (HTRR-CCU1-CO)	01	30600104	2a2	17	91.8	15.0%	78.1	13.78	0.2516	0.21	0.04	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
78	119090AAA	13872.0	ConocoPhillips Co	2911	0056	CO HEATER (HTRR-CCU2-CO)	01	30600104	2a2	80	82.1	15.0%	69.8	12.31	0.2249	0.19	0.03	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
79	119090AAA	13872.0	ConocoPhillips Co	2911	0085	HYDRODESULFURIZATION UNIT #1: CHARGE HEATER (	01	30600106	2a2	67.3	19.6	15.0%	16.6	2.94	0.0536	0.05	0.01	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
80	119090AAA	13872.0	ConocoPhillips Co	2911	0088	HYDRODESULFURIZATION UNIT #2: CHARGE HEATER (	01	30600106	2a2	81	26.2	15.0%	22.3	3.94	0.0719	0.06	0.01	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
81	119090AAA	13872.0	ConocoPhillips Co	2911	0093	CAT REFORMER #3: SECOND INTERREACTOR HEATER	02	30600106	2a2	74	27.1	15.0%	23.0	4.06	0.0742	0.06	0.01	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
82	119090AAA	13872.0	ConocoPhillips Co	2911	0154	VACUUM FLASHER #2: EAST HEATER (HTR-VF2-F203)	01	30600106	2a2	61	15.9	15.0%	13.5	2.39	0.0436	0.04	0.01	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
83	119090AAA	13872.0	ConocoPhillips Co	2911	0155	VACUUM FLASHER #1: NORTH HEATER (HTR-VF-1-NOR	01	30600105	2a2	100	45.5	15.0%	38.7	6.83	0.1247	0.11	0.02	NATURAL GAS	PETROLEUM INDUSTRY	PROCESS HEATE	NATURAL GAS-FIRED
84	119090AAA	13872.0	ConocoPhillips Co	2911	0156	VACUUM FLASHER #1: SOUTH HEATER (HTR-VF-1-SOUT	01	30600105	2a2	100	50.9	15.0%	43.3	7.64	0.1394	0.12	0.02	NATURAL GAS	PETROLEUM INDUSTRY	PROCESS HEATE	NATURAL GAS-FIRED
85	119813AAI	7044.1	US Steel Granite City	3312	0044	BOILER HOUSE 2: BOILER #11 - BLAST FURNACE DEPT	04	10200601	1a1	225	25.7	69.2%	7.9	17.78	0.0854	0.02	0.06	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
86	119813AAI	7044.1	US Steel Granite City	3312	0044	BOILER HOUSE 2: BOILER #11 - BLAST FURNACE DEPT	01	10200704	1a1	225	31.7	69.2%	9.8	21.96	0.0454	0.01	0.03	PROCESS GAS	EXTERNAL COMBUSTION B	PROCESS GAS	BLAST FURNACE GAS
87	119813AAI	7044.1	US Steel Granite City	3312	0048	BOILER HOUSE 2: BOILER #12 - BLAST FURNACE DEPT	04	10200601	1a1	225	24.8	69.2%	7.6	17.15	0.0456	0.01	0.03	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
88	119813AAI	7044.1	US Steel Granite City	3312	0048	BOILER HOUSE 2: BOILER #12 - BLAST FURNACE DEPT	01	10200704	1a1	225	21.2	69.2%	6.5	14.70	0.0436	0.01	0.03	PROCESS GAS	EXTERNAL COMBUSTION B	PROCESS GAS	BLAST FURNACE GAS
89	119813AAI	7044.1	US Steel Granite City	3312	0048	BOILER HOUSE 2: BOILER #12 - BLAST FURNACE DEPT	02	10200707	1a1	225	64.5	69.2%	19.9	44.67	0.138	0.04	0.10	PROCESS GAS	EXTERNAL COMBUSTION B	PROCESS GAS	COKE OVEN GAS

90	119813AAI	7044.1	US Steel Granite City	3312	0041	BOILER HOUSE 1. BOILERS 1 TO 7	01	10200704	1a2	60	66.0	15.0%	56.1	9.89	0.1502	0.13	0.02	PROCESS GAS	EXTERNAL COMBUSTION B	PROCESS GAS	BLAST FURNACE GAS
91	119813AAI	7044.1	US Steel Granite City	3312	0041	BOILER HOUSE 1. BOILERS 1 TO 7	04	10200601	1a2	420	44.6	15.0%	37.9	6.69	0.1538	0.13	0.02	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
92	119813AAI	7044.1	US Steel Granite City	3312	0041	BOILER HOUSE 1. BOILERS 1 TO 7	02	10200707	1a2	559	134.2	15.0%	114.0	20.12	0.4103	0.35	0.06	PROCESS GAS	EXTERNAL COMBUSTION B	PROCESS GAS	COKE OVEN GAS
93	119813AAI	7044.1	US Steel Granite City	3312	0042	BOILER HOUSE 1. BOILERS 8 TO 10	04	10200602	1a2	60	19.3	15.0%	16.3	2.87	0.0659	0.06	0.01	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	10-100 MMBTU/HR
94	119813AAI	7044.1	US Steel Granite City	3312	0042	BOILER HOUSE 1. BOILERS 8 TO 10	01	10200704	1a2	80	28.3	15.0%	24.0	4.24	0.0844	0.05	0.01	PROCESS GAS	EXTERNAL COMBUSTION B	PROCESS GAS	BLAST FURNACE GAS
95	119813AAI	7044.1	US Steel Granite City	3312	0042	BOILER HOUSE 1. BOILERS 8 TO 10	02	10200707	1a2	60	57.5	15.0%	48.9	8.63	0.1758	0.15	0.03	PROCESS GAS	EXTERNAL COMBUSTION B	PROCESS GAS	COKE OVEN GAS
96	119813AAI	7044.1	US Steel Granite City	3312	0015	SLAB FURNACE #1	02	39000689	7a	321.8	84.9	77.0%	19.5	65.40	0.4144	0.10	0.32	PROCESS GAS	IN-PROCESS FUEL USE	NATURAL GAS	GENERAL
97	119813AAI	7044.1	US Steel Granite City	3312	0015	SLAB FURNACE #1	01	39000689	7a	321.8	266.2	77.0%	61.2	205.00	0.7088	0.16	0.55	NATURAL GAS	IN-PROCESS FUEL USE	NATURAL GAS	GENERAL
98	119813AAI	7044.1	US Steel Granite City	3312	0018	SLAB FURNACE #4	01	39000689	7a	495	113.8	77.0%	26.2	87.65	0.9587	0.22	0.74	NATURAL GAS	IN-PROCESS FUEL USE	NATURAL GAS	GENERAL
99	119813AAI	7044.1	US Steel Granite City	3312	0122	SLAB FURNACE #2	02	39000689	7a	322	82.2	77.0%	18.9	63.32	0.3936	0.09	0.30	PROCESS GAS	IN-PROCESS FUEL USE	NATURAL GAS	GENERAL
100	119813AAI	7044.1	US Steel Granite City	3312	0122	SLAB FURNACE #2	01	39000689	7a	322	149.2	77.0%	34.3	114.89	0.6806	0.16	0.53	NATURAL GAS	IN-PROCESS FUEL USE	NATURAL GAS	GENERAL
101	119813AAI	7044.1	US Steel Granite City	3312	0123	SLAB FURNACE #3	02	39000689	7a	322	101.6	77.0%	23.4	78.19	0.4321	0.10	0.33	PROCESS GAS	IN-PROCESS FUEL USE	NATURAL GAS	GENERAL
102	119813AAI	7044.1	US Steel Granite City	3312	0123	SLAB FURNACE #3	01	39000689	7a	322	162.8	77.0%	37.5	125.39	0.7052	0.16	0.54	NATURAL GAS	IN-PROCESS FUEL USE	NATURAL GAS	GENERAL
103	157851AAA	4875.6	Dynegy Midwest Generation Inc	4911	0001	*BOILER #1	01	10100202	8a	5890	1108.9	-20.0%	1328.3	-221.39	3.627	4.35	-0.73	COAL - SUBBITUMINOUS			
104	157851AAA	4875.6	Dynegy Midwest Generation Inc	4911	0002	*BOILER #2	01	10100202	8a	5900	1486.3	-22.2%	1827.6	-332.29	3.547	4.54	-0.79	COAL - SUBBITUMINOUS			
105	157851AAA	4875.6	Dynegy Midwest Generation Inc	4911	0013	*BOILER #3	01	10100202	8a	5800	2271.8	7.8%	2095.0	176.81	6.624	6.11	0.52	COAL - SUBBITUMINOUS			
106	163045ADT	168.3	Elementis Pigments Inc	2816	0061	Erie City boiler	01	10200601	1a1	135	41.4	69.2%	12.7	28.65	0.258	0.08	0.18	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
107	163121AAY	250.1	Environmental Management Corp	4961	0001	BOILERS #1, #2 AND #3	01	10200601	1a1	393	22.4	69.2%	6.9	15.53	0.0653	0.02	0.04	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
108	197090AAI	2877.3	CITGO Petroleum Corp	2911	0017	430B-1: Auxiliary boiler	01	10200701	1a1	396	120.5	69.2%	37.1	83.42	0.3298	0.10	0.23	PROCESS GAS	EXTERNAL COMBUSTION B	PROCESS GAS	> 100 MBTU/HR
109	197090AAI	2877.3	CITGO Petroleum Corp	2911	0235	431B-20: North Plant Boiler	01	10200501	1b1	249	22.3	52.4%	10.6	11.69	0.0388	0.02	0.02	DISTILLATE OIL #2	EXTERNAL COMBUSTION B	DISTILLATE OIL	GRADES 1 AND 2 OIL
110	197090AAI	2877.3	CITGO Petroleum Corp	2911	0003	111B-1A: Atmospheric heater	01	30600104	2a1	376.5	46.4	28.6%	33.1	13.25	0.1345	0.10	0.04	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
111	197090AAI	2877.3	CITGO Petroleum Corp	2911	0004	111B-1B: Atmospheric heater	01	30600104	2a1	376.5	47.2	28.6%	33.7	13.47	0.1362	0.10	0.04	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
112	197090AAI	2877.3	CITGO Petroleum Corp	2911	0006	111B-2: Crude vacuum heater	01	30600104	2a1	219.8	18.1	28.6%	12.9	5.17	0.057	0.04	0.02	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
113	197090AAI	2877.3	CITGO Petroleum Corp	2911	0050	109B-62: Steam HC reformer heater	01	30600104	2a1	113.3	55.2	28.6%	39.5	15.78	0.1751	0.13	0.05	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
114	197090AAI	2877.3	CITGO Petroleum Corp	2911	0070	121B-2: Feed preheater	01	30600106	2a1	121.2	54.5	28.6%	38.9	15.56	0.1428	0.10	0.04	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
115	197090AAI	2877.3	CITGO Petroleum Corp	2911	0011	113B-1: Coker 1 charge heater	01	30600104	2a2	88.8	16.0	15.0%	13.6	2.40	0.0439	0.04	0.01	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
116	197090AAI	2877.3	CITGO Petroleum Corp	2911	0012	113B-3: Coker 1 charge heater	01	30600104	2a2	88.8	26.7	15.0%	22.7	4.00	0.0721	0.06	0.01	OTHER GASEOUS FUEL	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
117	197090AAI	2877.3	CITGO Petroleum Corp	2911	0019	116B-1: Charge heater and stabilizer reboiler	01	30600104	2a2	89.9	41.5	15.0%	35.3	6.23	0.1188	0.10	0.02	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
118	197090AAI	2877.3	CITGO Petroleum Corp	2911	0021	118B-1: Hot oil heater	01	30600104	2a2	93.8	15.6	15.0%	13.3	2.35	0.044	0.04	0.01	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
119	197090AAI	2877.3	CITGO Petroleum Corp	2911	0048	108B-41: Process heater	01	30600104	2a2	44	22.7	15.0%	19.3	3.41	0.0614	0.05	0.01	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
120	197090AAI	2877.3	CITGO Petroleum Corp	2911	0064	113B-2: Coker 1 charge heater	01	30600106	2a2	81.8	16.4	15.0%	13.9	2.46	0.045	0.04	0.01	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
121	197090AAI	2877.3	CITGO Petroleum Corp	2911	0066	116B-2: Interheater and naphtha stripper reboiler	01	30600106	2a2	84.2	24.9	15.0%	21.1	3.73	0.0816	0.07	0.01	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
122	197090AAI	2877.3	CITGO Petroleum Corp	2911	0073	123B-5: Reheat furnace	01	30600106	2a2	42	17.5	15.0%	14.9	2.63	0.0472	0.04	0.01	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
123	197090AAI	2877.3	CITGO Petroleum Corp	2911	0074	125B-1 and 125B-2: Feed heater and stripper reboil	01	30600106	2a2	100	32.0	15.0%	27.2	4.80	0.0863	0.07	0.01	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
124	197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0002	AUX BOILER	03	30600104	1a1	600	35.6	69.2%	11.0	24.65	0.1013	0.03	0.07	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	> 100 MBTU/HR
125	197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0018	Crude unit heaters (#1B1A and #1B1B)	01	30600104	2a1	778	288.3	28.6%	206.0	82.42	0.7786	0.56	0.22	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
126	197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0019	Crude unit vacuum heater	01	30600106	2a1	277	117.5	28.6%	83.9	33.58	0.3157	0.23	0.09	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
127	197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0021	Coker charge heaters (East and West)	01	10200701	2a1	732	123.3	28.6%	88.1	35.23	0.3185	0.23	0.09	PROCESS GAS	EXTERNAL COMBUSTION B	PROCESS GAS	PETROLEUM REFINERY GAS
128	197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0025	Reformer charge heaters (2B3, 2B4, 2B5, 2B6)	01	30600106	2a1	680	97.6	28.6%	69.7	27.89	0.2583	0.19	0.07	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
129	197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0028	Pretreat debut reboil 17-B-2	01	10200701	2a1	164	15.8	28.6%	11.3	4.50	0.0454	0.03	0.01	PROCESS GAS	EXTERNAL COMBUSTION B	PROCESS GAS	PETROLEUM REFINERY GAS
130	197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0033	CHD reset charge heater 3B1	01	30600104	2a1	158	41.4	28.6%	29.6	11.83	0.1163	0.08	0.03	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	GAS FIRED
131	197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0034	CHD strip reboiler 3B2	01	10200701	2a1	129	42.6	28.6%	30.4	12.16	0.1063	0.08	0.03	PROCESS GAS	EXTERNAL COMBUSTION B	PROCESS GAS	PETROLEUM REFINERY GAS
132	197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0038	Alky isostrip reboiler heater 7B1	01	10200701	2a1	171	34.3	28.6%	24.5	9.73	0.1065	0.08	0.03	PROCESS GAS	EXTERNAL COMBUSTION B	PROCESS GAS	PETROLEUM REFINERY GAS
133	197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0113	Crude unit feed preheater 1-B3/13-B-4	01	30600106	2a1	240	30.7	28.6%	21.9	8.77	0.0848	0.06	0.02	PROCESS GAS	PETROLEUM INDUSTRY	PROCESS HEATE	PROCESS GAS-FIRED
134	197800AAA	7896.2	Exxon Mobil Oil Corp	2911	0038	Alky isostrip reboiler heater 7B1	02	30600103	2b1	171	23.3	76.2%	5.5	17.74	0.0896	0.02	0.05	RESIDUAL OIL #4	PETROLEUM INDUSTRY	PROCESS HEATE	OIL FIRED
135	197800AAD	198.2	Loders Croklaan USA	2079	0043	JOHNSTON BOILER	01	10200602	1a2	91.7	41.5	15.0%	35.3	6.23	0.114	0.10	0.02	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	10-100 MMBTU/HR
136	197800ABZ	1056.4	Flint Hills Resources LP	2865	0121	2 BOILERS (CB-703, CB-704)	01	10200601	1a1	450	55.2	69.2%	17.0	38.24	0.1628	0.05	0.11	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
137	197800ABZ	1056.4	Flint Hills Resources LP	2865	0119	BOILER CB-706	01	10200601	1a1	370.2	17.8	69.2%	5.5	12.30	0.0254	0.01	0.02	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
138	197809AAC	227.0	Caterpillar Inc	3531	0004	Boiler #2	01	10200601	1a1	112.6	16.1	69.2%	5.0	11.15	0.0837	0.03	0.06	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
139	197809AAC	227.0	Caterpillar Inc	3531	0005	Boiler #3	01	10200601	1a1	175	40.0	69.2%	12.3	27.66	0.079	0.02	0.06	NATURAL GAS	EXTERNAL COMBUSTION B	NATURAL GAS	> 100 MBTU/HR
140	197809AAO	60970.8	Midwest Generation LLC	4911	0009	Joliet 9: Unit 6 cyclone boiler	01	10100203	8a	2886	5418.6	81.9%	981.2	4437.33	16.9076	3.06	13.85	COAL - SUBBITUMINOU	EXTERNAL COMBUSTION B	BITUMINOUS CO	CYCLONE FURNACE
141	197809AAO	60970.8	Midwest Generation LLC	4911	0031	Joliet 29: Unit 7 Boilers 71 and 72	01	10100202	8a	4558	1760.7	25.0%	1320.5	440.16	8.0416	4.53	1.51	COAL - SUBBITUMINOU	EXTERNAL COMBUSTION B	BITUMINOUS CO	PULVERIZED COAL DRY BOTTOM
142	197809AAO	60970.8	Midwest Generation LLC	4911	0033	Joliet 29: Unit 8 Boilers 81 and 82	01	10100202	8a	3193	1879.2	26.2%	1386.3	492.89	5.9909	4.42	1.57	COAL - SUBBITUMINOU	EXTERNAL COMBUSTION B	BITUMINOUS CO	PULVERIZED COAL DRY BOTTOM
143	197810AAK	18014.4	Will County Electric Generating St	4911	0010	UNIT #1 BOILER CYCLONE	02	10100223	8a	1728	2679.0	85.1%	397.9	2281.09	9.5884	1.42	8.17	COAL - SUBBITUMINOU	EXTERNAL COMBUSTION B	SUBBITUMINOUS	CYCLONE FURNACE
144	197810AAK	18014.4	Will County Electric Generating St	4911	0012	UNIT #2 BOILER CYCLONE	02	10100223	8a	1712	2531.0	83.1%	426.6	2104.41	9.1506	1.54	7.61	COAL - SUBBITUMINOU	EXTERNAL COMBUSTION B	SUBBITUMINOUS	CYCLONE FURNACE
145	197810AAK	18014.4	Will County Electric Generating St	4911	0014	UNIT #3 BOILER PULV. DRY BOTTOM - TANGENTIALY F	02	10100222	8a	2709	873.1	23.1%	671.6	201.48	2.7744	2.13	0.64	COAL - SUBBITUMINOU	EXTERNAL COMBUSTION B	SUBBITUMINOUS	PULVERIZED COAL DRY BOTTOM
146	197810AAK	18014.4	Will County Electric Generating St	4911	0016	UNIT #4 BOILER PULV. DRY BOTTOM - TANGENTIALY F	02	10100222	8a	5016	1690.3	35.7%	1086.9	603.86	6.0884	3.92	2.18	COAL - SUBBITUMINOU	EXTERNAL COMBUSTION B	SUBBITUMINOUS	PULVERIZED COAL DRY BOTTOM
						All Sources in Chicago and Metro-East NAAs, Total				**98419**	**44625**	**46.3%**	**23959**	**20666**	**143**	**74**	**69**				

Table I-1: NOx Reductions from the Application of NOx RACT (Reductions by Categories)

Mydocument/TSD/NOx RACT-Attachments.xls

Emission Category Description	Category Designation	No. of Entries	No. of Units	Heat Input mmbtu/hr	2005 NOx Emissions tpy	Estimated NOx RACT Reduction , %	Estimated Controlled NOx tpy	Estimated Nox Reduction Tons	Unit Typical Ozone Season NOx tons/day	Estimated Ozone Season Controlled NOx, TPD	Estimated Ozone season NOx Reduction, TPD
Chicago NAA											
Gaseous Fuel-fired Boilers >100 mmBtu/hr, Total	1a1	22	34	6911.9	1196.5	69.2%	368.2	828.3	2.79	0.86	1.93
Gaseous fuel-fired Boilers < =100 mmBtu/hr, Total	1a2	6	20	1273.9	156.6	15.0%	133.1	23.5	0.63	0.54	0.09
Dist. oil Boilers >100 mmBtu/hr, Total	1b1	1	1	249	22.3	52.4%	10.6	11.7	0.040	0.02	0.02
Solid Fuel Boilers >250 mmbtu/hr, Total	1e2	3	3	997.5	2330.2	73.9%	607.9	1722.3	8.93	2.33	6.60
Solid Fuel <=250, >100 mmbtu/hr, Total	1e3	1	1	212	21.6	63.8%	7.8	13.8	0.00	0.00	0.00
Solid Fuel Boilers <=100 mmbtu/hr, Total	1e4	5	5	376.2	476.7	15.0%	405.2	71.5	1.61	1.37	0.24
Process Htrs Gas fired >100 mmBtu/hr, Total	2a1	16	41	6672.6	1526.0	28.6%	1090.0	436.0	4.19	2.99	1.20
Process Htrs Gas-fired< =100 mmBtu/hr, Total	2a2	9	10	720.3	213.3	15.0%	181.3	32.0	0.60	0.51	0.09
Process Htrs, Residual Oil-fired, >100 mmBtu/hr, Total	2b1	1	1	171	23.3	76.2%	5.5	17.7	0.07	0.02	0.05
Process Htrs, Other Oil-fired, <100 mmBtu/hr, Total	2c3	1	1	17	26.5	15.0%	22.5	4.0	0.10	0.09	0.02
Glass melting Furnaces, Total	3	1	4	45	731.9	50.0%	366.0	366.0	2.02	1.01	1.01
Lime Kilns, Total	5a	2	2	588.9	734.4	30.0%	514.1	220.3	2.54	1.78	0.76
Annealing Furnace, Iron and Steel, Total	7b	1	1	123	44.1	60.0%	17.6	26.5	0.15	0.06	0.09
EGU Coal-fired Boilers, Total	8a	13	15	37802	24827.2	57.3%	10612.9	14214.3	82.22	34.59	47.63
All Sources in Chicago NAA, Total		82	139	56160.30	32331	56%	14343	17988	105.9	46.2	59.7
Metro-East NAA											
Gaseous Fuel-fired Boilers >100 mmBtu/hr, Total	1a1	10	6	3460	730.1	69.2%	224.6	505.4	2.02	0.62	1.40
Gaseous Fuel-fired Boilers <=100 mmBtu/hr, Total	1a2	7	10	1305	364.9	15.0%	310.2	54.7	1.06	0.90	0.16
Process Htrs Gas fired >100 mmBtu/hr, Total	2a1	16	16	2776.7	2184.4	28.6%	1560.3	624.1	6.58	4.70	1.88
Process Htrs Gas fired <100 mmBtu/hr, Total	2a2	15	15	1395.3	765.2	15.0%	650.4	114.8	2.10	1.78	0.31
Reheat Furnaces, Iron and Steel, Total	7a	8	5	2681.6	1008.5	77.0%	231.9	776.5	4.62	1.06	3.56
EGU Coal-fired Boilers, Total	8a	5	5	22540	7241	8.3%	6639	602	20.6	18.8	1.8
All Sources in Metro-East NAA, Total		61	57	34158.60	12294	21.8%	9617	2678	37.0	27.9	9.1
Chicago and Metro-East NAA (Combined)											
Gaseous Fuel-fired Boilers >100 mmBtu/hr, Total	1a1	32	40	10371.9	1926.5	69%	592.8	1333.8	4.8	1.5	3.3
Gaseous fuel-fired Boilers < =100 mmBtu/hr, Total	1a2	13	30	2578.9	521.5	15%	443.3	78.2	1.7	1.4	0.3
Dist. oil Boilers >100 mmBtu/hr, Total	1b1	1	1	249	22.3	52.4%	10.6	11.7	0.040	0.02	0.02
Solid Fuel Boilers >250 mmbtu/hr, Total	1e2	3	3	997.5	2330.2	73.9%	607.9	1722.3	8.93	2.33	6.60
Solid Fuel <=250, >100 mmbtu/hr, Total	1e3	1	1	212	21.6	63.8%	7.8	13.8	0.00	0.00	0.00
Solid Fuel Boilers <=100 mmbtu/hr, Total	1e4	5	5	376.2	476.7	15.0%	405.2	71.5	1.61	1.37	0.24
Process Htrs Gas fired >100 mmBtu/hr, Total	2a1	32	57	9449.3	3710.4	0.6	2650.3	1060.1	10.8	7.7	3.1
Process Htrs Gas-fired< =100 mmBtu/hr, Total	2a2	24	25	2115.6	978.5	0.3	831.7	146.8	2.7	2.3	0.4
Process Htrs, Residual Oil-fired, >100 mmBtu/hr, Total	2b1	1	1	171	23.3	76.2%	5.5	17.7	0.07	0.02	0.05
Process Htrs, Other Oil-fired, <100 mmBtu/hr, Total	2c3	1	1	17	26.5	15.0%	22.5	4.0	0.10	0.09	0.02
Glass melting Furnaces, Total	3	1	4	45	731.9	50.0%	366.0	366.0	2.02	1.01	1.01
Lime Kilns, Total	5a	2	2	588.9	734.4	30.0%	514.1	220.3	2.54	1.78	0.76
Reheat Furnaces, Iron and Steel, Total	7a	8	5	2681.6	1008.5	77.0%	231.9	776.5	4.62	1.06	3.56
Annealing Furnace, Iron and Steel, Total	7b	1	1	123	44.1	60.0%	17.6	26.5	0.15	0.06	0.09
EGU Coal-fired Boilers, Total	8a	18	20	60342.00	32068.6	46.2%	17252.1	14816.5	102.9	53.4	49.4
All Sources in Chicago and Metro-East NAA, Total		143	196	90318.9	44625	46.31%	23959	20666	142.9	74.1	68.9

Tabulation by Broad Categories

Industrial Boilers			45		4300.68	71.7%	1219.12	3081.56
Industrial Boilers			35		998.2	15.0%	848.4	149.7
Process Heaters			58		3733.7	28.9%	2655.8	1077.9
Process Heaters			26		1004.95	15.0%	854.21	150.74
Glass Melting Furnaces			4		732	50%	366	366
Lime Kilns, Total			2		734	30%	514	220
Iron and Steel, (reheat, annealing and galvanizing furnaces)			2		1052.6	76.3%	249.6	803.0
EGU Coal-fired Boilers, Total			20		32068.6	46.2%	17252.1	14816.5